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NORTH AMERICAN NATURAL GAS RESERVES AND RESOURCES

HEARING

BEFORE THE

SUBCOMMITTEE ON ENERGY REGULATION

OF THE

COMMITTEE ON
ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

NINETY-EIGHTH CONGRESS

SECOND SESSION

ON THE

NORTH AMERICAN NATURAL GAS RESERVES AND RESOURCES

APRIL 26, 1984

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NORTH AMERICAN NATURAL GAS RESERVES AND RESOURCES

THURSDAY, APRIL 26, 1984

U.S. SENATE,
SUBCOMMITTEE ON ENERGY REGULATION,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, DC.

The subcommittee met, pursuant to notice, at 2 p.m., in room SD-366, Dirksen Office Building, Hon. Frank H. Murkowski presiding.

Present: Senator Murkowski.

Also present: Howard Useem, professional staff member; and Elizabeth Moler, counsel for the minority.

OPENING STATEMENT OF HON. FRANK H. MURKOWSKI, A U.S. SENATOR FROM THE STATE OF ALASKA

Senator MURKOWSKI. The hearing will come to order.

This hearing is before the Subcommittee on Energy Regulation of the Committee on Energy and Natural Resources.

I want to welcome all witnesses that are appearing before the subcommittee today. I know that many of you have traveled from long distances. We appreciate your interest and we look forward to your contribution in establishing a record on this most important subject.

Today's oversight hearing will review North America's natural gas reserves and resources.

My interest in this matter is that determining how and when Alaska's considerable reserves of natural gas located on the North Slope will be brought to market.

It's been estimated that one-sixth of the U.S. proven natural gas reserves are located in Alaska, and largely due to the uncertainties in the lower 48 gas market, it appears to us and many others that little progress has been made to date in moving Alaska gas to market.

If there is an adequate supply of gas available in the U.S. market from Mexico, the contiguous 48 States and Canada, then it would seem to make good economic sense from both Alaska's and the U.S. perspective to look at possible alternative foreign markets for sale of Alaska's gas.

On the other hand, if needed supplies of gas are not available from these sources, then one has to question why the construction of the Alaska Natural Gas Transportation System should not begin as soon as possible.

For the record, I would like to note that the Canadian producers and representatives of the Canadian National Energy Board were invited to testify, but they declined to do so.

Therefore, in order to help complete the record, I intend to insert into that record a report published by the Geological Survey of Canada entitled "Oil and Natural Gas Resources of Canada in 1983."

This report states that Canada has 106 Tcf of established gas reserves and discovered gas resources, and that they expect to find another 336 Tcf of additional gas, which would give that country a total of 442 Tcf of gas.

In western Canada alone, the comparable figure for established and potential reserves is 163 Tcf of gas. It is my understanding that that figure does not include the rich Beaufort Sea and McKensie Delta regions of the Canadian Arctic.

The report, however, does not indicate the portion of those reserves which will become commercially producible.

Because there is no consensus in Canada regarding the specific development, production and transportation systems which will be employed in bringing these resources to market, it is, therefore, very difficult to predict how much of this gas will find its way ultimately into the markets in the United States.

I believe that we can safely presume, however, that the volumes will be substantial.

Canada currently consumes domestically less than 2 Tcf of gas each year. Its current export policy allows volumes in excess of a 25-year domestic supply cushion to be exported.

Even if this strict policy is continued—and there are signs it may instead be actually eased—simple calculations suggest that Canada may be in a position to export as much as 400 Tcf of gas to the United States in the years ahead.

At the current level of U.S. imports, this represents more than a 400-year supply of gas from Canada.

In addition, there is a great deal more gas to be found in the United States. I expect that we will hear more today from our witnesses on that subject. The Potential Gas Committee, for example, estimates the United States holds 875 Tcf of undiscovered gas. At current rates of consumption, that's in excess of a 50-year supply.

The implications of the substantial gas resources located in Canada and the lower 48 on plans to market Alaska's gas in the lower 48 are obvious at this time.

Because Canadian gas is filling the incremental demand for additional supplies of gas, I am inclined to think that Alaska's gas cannot be marketed in the lower 48 until the Canadians no longer wish to supply that U.S. market.

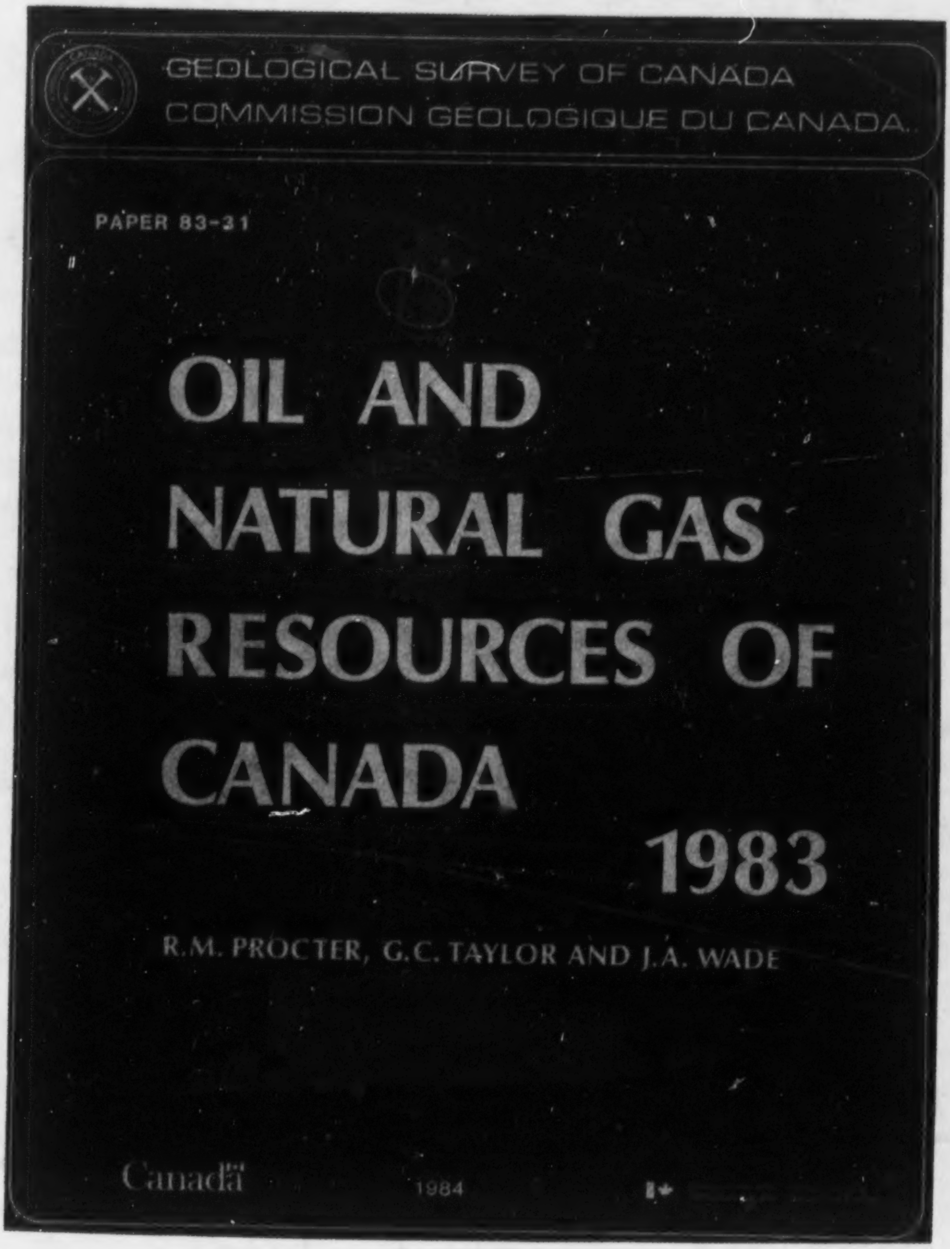
Canada currently appears to be ready and willing to continue to price their gas at a level slightly below that of Alaska gas for the foreseeable future.

Of course, the purpose and the value of the hearing goes beyond the important issue of Alaskan gas. It's implications are for all aspects of domestic energy policy, including gas pricing and fuel use distribution.

Gas resources become available reserves only if they are made available for exploration and production, and only if production economics warrant such action.

Moreover, gas can be marketed only if a means for transporting it is available. However, these other issues are not the direct focus of the hearing today.

[The report submitted by Senator Murkowski follows:]



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PAPER 83-31

OIL AND NATURAL GAS RESOURCES OF CANADA 1983

R.M. PROCTER, G.C. TAYLOR AND J.A. WADE

Canada
1984

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1983

by R. M. PROCTER, G. C. TAYLOR
and J. A. WADE

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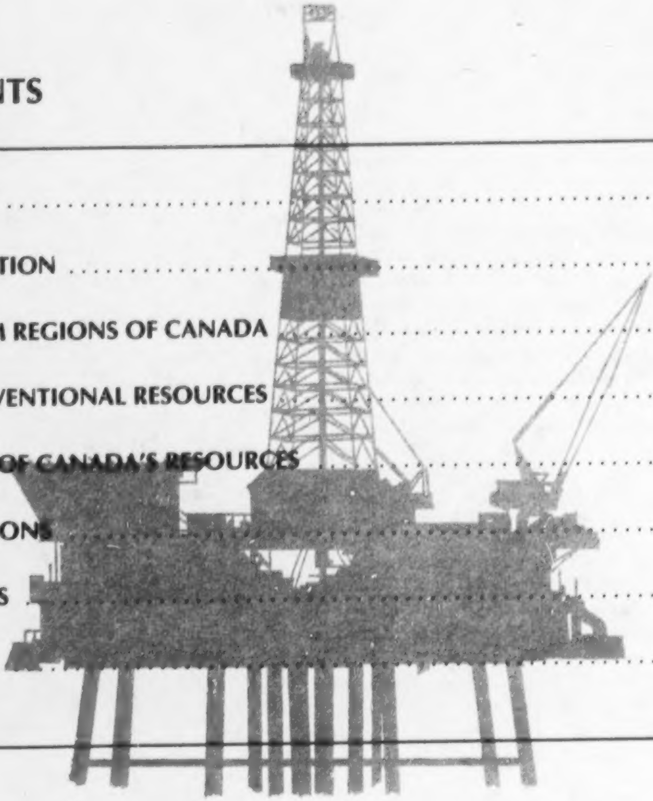

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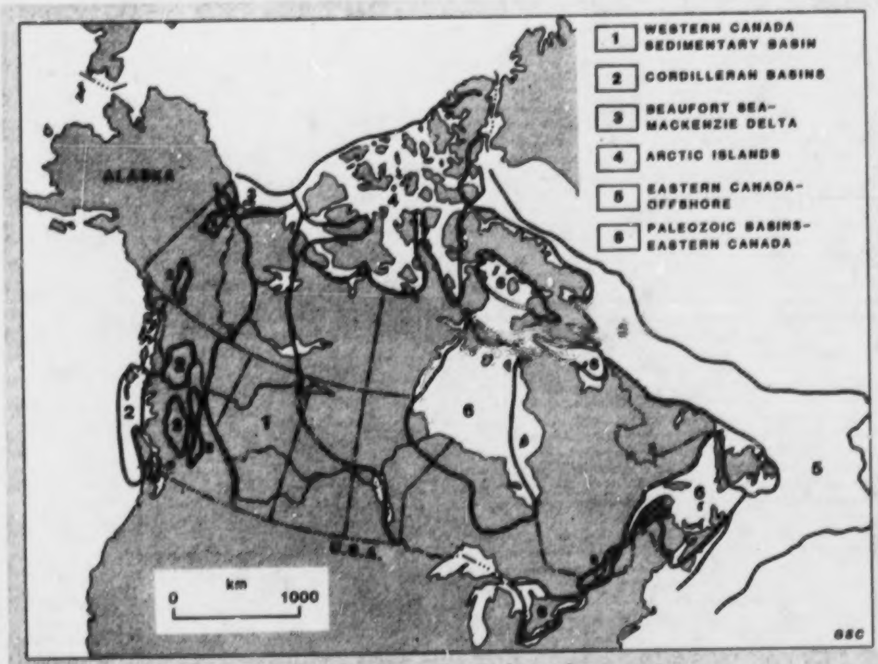
SUMMARY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2 CORDILLERAN BASINS
3 BEAUFORT SEA–MACKENZIE DELTA
4 ARCTIC ISLANDS
5 EASTERN CANADA–OFFSHORE
6 PALEOZOIC BASINS–EASTERN CANADA
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Figure 1.1 Canada's petroleum regions

The oil and natural gas resources of Canada are evaluated on a systematic basis by the Geological Survey of Canada. This report summarizes the current estimates of quantities of oil and natural gas that are inferred to exist but not yet discovered. The analysis of resources is made for each of Canada's six petroleum regions (Figure 1.1), addressing both conventional and non-conventional resources. The present report, which replaces "Oil and Natural Gas Resources of Canada — 1976" published by Energy, Mines and Resources in 1977, contains major revisions and new estimates for most parts of Canada. The estimates of potential resources, those inferred to exist but as yet undiscovered, prepared by the Geological Survey of Canada are supplemented by estimates of reserves, or discovered resources, provided by the Canada Oil and Gas Lands Administration for frontier areas; and by the National Energy Board for the Western Canada Sedimentary Basin.

Conventional Resources

Canada is well endowed with oil and gas resources. Current estimates of remaining established reserves of oil are 754 million cubic metres, and of gas 2111 billion cubic metres, all located in Western Canada. To these can be added the best current estimates of discoveries in frontier areas, which increases the discovered portion of Canada's conventional resources to an estimated 1173 million cubic metres of oil and 3013 billion cubic metres of gas. Estimates by region, summarized in Table I, indicate that significant oil and gas reserves have been identified in Eastern Canada Offshore and in the Mackenzie Delta-Beaufort Sea regions. Important gas reserves also have been discovered in the Arctic Islands region.

Estimates of oil and gas potential are prepared using a probability methodology that expresses the range of quantities that may exist, along with the probability or confidence level associated with different parts of that range. Throughout the report, the estimates of potential are expressed at three levels of confidence, as in Table I. The values contained in Table I are also displayed in figures 1.2 and 1.3 which permit an easy comparison of the relative potential estimated for each region. The figures indicate that the potential for oil is greatest in the Eastern Canada Offshore region, followed by the Beaufort Sea-Mackenzie Delta region, both areas having greater potential than Western Canada. Gas potential however, is estimated to be more evenly distributed in four regions.

Non-conventional Resources

In addition to the conventional resources, Canada is more richly endowed with non-conventional oil and gas resources than most countries. These resources dwarf the conventional category in terms of total quantity of in-place reserves, and have the added advantage of already having been discovered. The costs associated with their development, and the need for new cost-reducing extraction technology do not permit reliable estimates of recoverable reserves in the same context as those shown in Table I, but remaining established reserves of synthetic crude oil are estimated to be 3060 million cubic metres. Also, not listed in Table I, and sharing in the uncertainty of costs and new technology, is potential that may result from enhanced oil recovery applications to Western Canada reserves. This process is estimated to have potential for an additional 500 million cubic metres of oil as an average expectation.

Supply Considerations

Canada's future oil supply will derive from some mix of conventional, frontier, heavy oil and non-conventional sources. The proportion of each will depend on many factors including comparative economics, developments in technology, and investment strategies. Figure 1.4 is an attempt to illustrate Canada's currently identified total oil resources as a possible inventory from which future supply may be selected. No quantity values are identified for segments in the figure because reliable estimates of recoverable oil from in-situ oil sands development and tertiary recovery methods in heavy oil are not available and some arbitrary, probably conservative, recovery factors have been assumed: The proportions are adequate however to compare short term supply options at least in terms of what is already known to exist. A decade of continued exploration may modestly increase the Western Canada segment, and could easily double the size of the "Frontiers" segments. However, the oil resources associated with oil sands will continue to dominate the inventory in a quantitative sense. Figure 1.4 is of course incomplete and potentially misleading in that the economic viability of each segment can vary by orders of magnitude — a factor not considered in the diagram, and beyond the scope of this study.

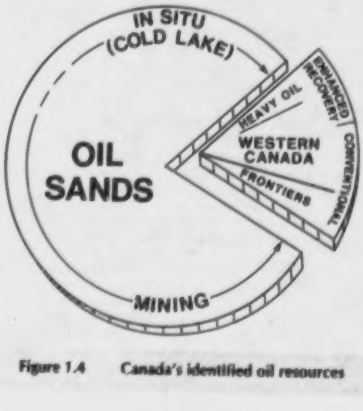


Figure 1.4 Canada's identified oil resources

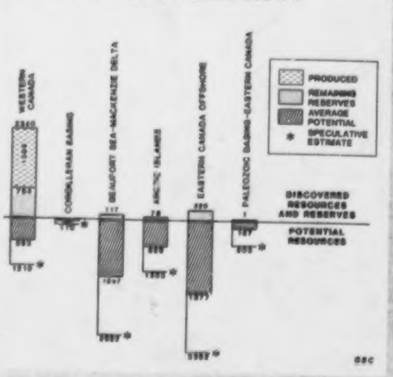


Figure 1.2 Conventional oil resources of Canada

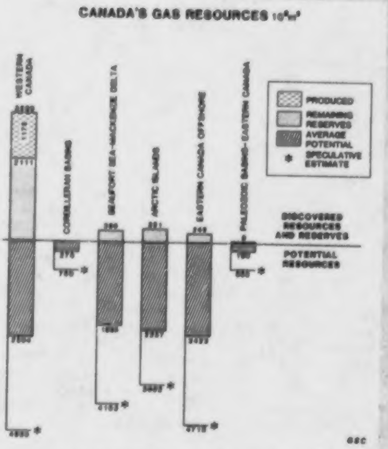


Figure 1.3 Conventional gas resources of Canada

TABLE I CONVENTIONAL OIL AND GAS RESOURCES OF CANADA

	RESERVES AND DISCOVERED RESOURCES	POTENTIAL		
		High Confidence	Average Expectation	Speculative Estimates
Oil 10^6m^3 (Recoverable)				
Western Canada Sedimentary Basin	754	234	593	1210
Cordilleran Basins	—	—	50	110
Beaufort Sea-MacKenzie Delta	117	307	1347	2962
Arctic Islands	76	316	686	1305
Eastern Canada Offshore	225	512	1877	3392
Paleozoic Basins - Eastern Canada	0.8	20	167	605
TOTAL	1173	*1486	4720	*8995
Gas 10^9m^3 (Recoverable)				
Western Canada Sedimentary Basin	2111	1544	2504	4930
Cordilleran Basins	—	40	270	760
Beaufort Sea-MacKenzie Delta	286	871	1865	4103
Arctic Islands	361	1100	2257	3662
Eastern Canada Offshore	246	725	2423	4713
Paleozoic Basins - Eastern Canada	8.8	46	190	660
TOTAL	3013	*4342	9509	*10285

* These numbers do not add arithmetically but must be summed using statistical techniques.

CONCLUSIONS

Conventional Resources

Canada's potential oil and natural gas resources are large and could ensure self-sufficiency if means can be found to convert a significant portion of them into economic reserves. The potential for future discovery is greater in the frontier regions than in western Canada. This is due to the degree of exploration maturity of the Western Canada Sedimentary Basin.

The portion of these resources that is, or will be, commercially viable depends on prevailing economic conditions as affected by technological progress in development, production and transportation. To date there has been no consensus regarding specific development, production and transportation systems suitable for frontier discoveries, particularly for offshore areas. This has hampered the ability to estimate the contribution that frontier resources can make to future Canadian energy supplies. The Department is working towards providing estimates that can be used with a reasonable degree of confidence.

The pace of exploration, and therefore the rate at which frontier resources are discovered, will be affected by factors that include exploration success; expectations regarding market prices, development and operating costs; prevailing fiscal regimes; technological progress; and successful commercial exploitation of discoveries already made. Lead times from discovery to commercial development are long in frontier regions and it is unlikely that large-volume frontier production will be available to Canadian markets until the 1990's.

For the balance of this decade therefore, domestic oil supply will have to depend primarily on western Canada reserves. Infrastructure already in place in this area ensures that newly-found conventional reserves can be quickly placed on production, however more intensive exploration efforts will be needed to accelerate discovery. Enhanced recovery of existing light and medium crude oil reserves and of heavy crude oil can, as well, make a substantial contribution to supply over this period.

Oil supply beyond 1990 will likely include production from frontier discoveries in the East Newfoundland Shelf, Arctic and the Beaufort Sea regions. Given the appropriate economic climate, additional in-situ oil sands projects, surface mining oil sands plants, heavy oil and an increasing quantity of enhanced recovery supply can also be viewed within this time-frame, as well as a continuing contribution from conventional oil from the Western Canada Basin.

In addition to development of oil deposits already taking place in the Mackenzie Corridor, pipeline access to the northern frontiers would open other oil resources of the Mackenzie Corridor to southern markets.

Gas potential estimated in all frontiers plus western Canada, in addition to present reserves, indicates an assured supply. These resources should meet current requirements as well as expansions of Canadian gas markets for the foreseeable future. This will, of course, require development investments to maintain and expand delivery capacity from western Canada.

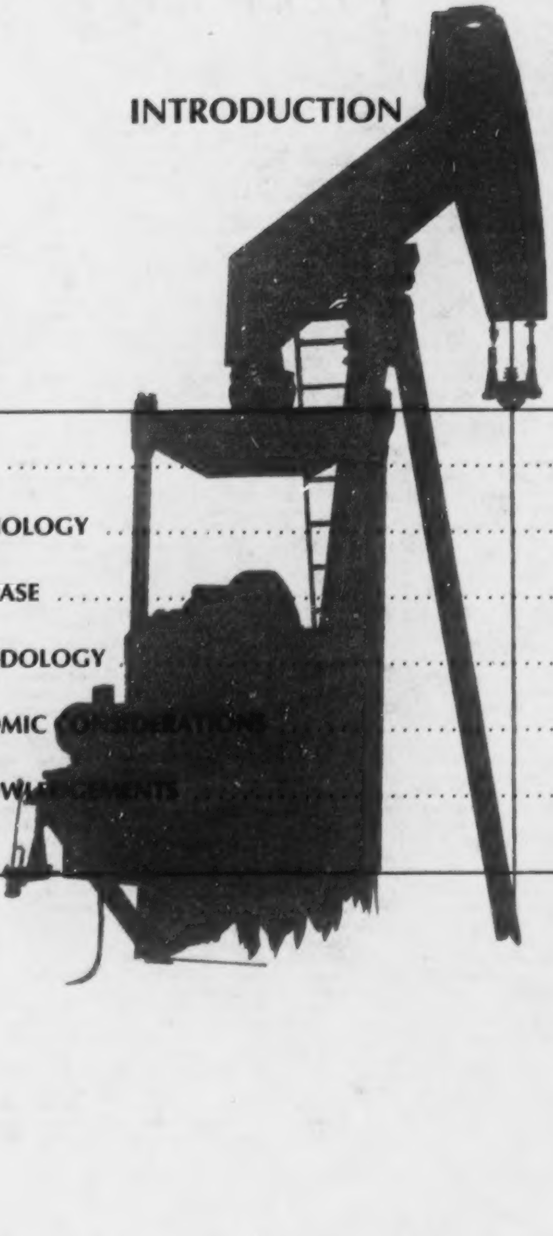
Major current limitations on frontier gas development are high development, operating and transportation costs, and lack of markets. In addition, remote frontier projects face technological and environmental hurdles.

Non-Conventional Oil Resources

The future mix of non-conventional and conventional resources in supplying domestic energy requirements will depend on the relative costs of exploration, development, operation and delivery to market.

Canada has a large potential supply of oil from heavy oil reservoirs and oil sands deposits. These resources represent a known source of supply, probably exceeding conventional oil resources in terms of quantity ultimately producible. Available upgrading technology together with development and operating costs are the limiting factors in bringing these supplies to the Canadian market. Although the technology for heavy oil and bitumen extraction exists at this time, a full realization of the potential from in-situ recovery and heavy oils will require advances in upgrading technology. Small scale upgrading projects could allow technology demonstration and improvements and hopefully will lead to larger scale projects.

INTRODUCTION



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INTRODUCTION

This document replaces the "Oil and Natural Gas Resources of Canada 1976", E.M.R. Report EP77-1. Since 1976 additional data and information regarding the geology of Canada's petroleum basins has been assembled and analysed. The current report contains revisions and new estimates for many regions based on this improved data base.

Oil and natural gas remain the major sources of Canada's primary energy requirements. Although requirements for these fuels have been reduced through energy conservation and efforts to promote substitutes for oil, this dependence will continue. Despite the vigorous exploration effort since 1976, Canada has seen a decline in the amount of petroleum in actual reserves. Major new discoveries have been made in the frontier regions of Canada but because of their nature and current economics their commercial development will be delayed a number of years. Also, changes in the world economic climate have deferred anticipated production from the non-conventional resources, particularly major oil sands and proposed heavy oil projects.

Thus there remains as a major requirement the 'need-to-know', in ever increasing sophistication, the nation's endowment of petroleum resources. A series of questions can be formulated concerning these resources which are fundamental to the planning and decision making process within the investment community and are essential for rational government policy consideration.

1. How much oil and gas is likely to exist in Canada?
2. What is the geographic distribution of these oil and gas resources among frontier basins and the established producing areas?
3. What degree of confidence can be attached to these estimates of petroleum resources?
4. What are the likely rates of discovery and development of production capability from these resources?
5. What is the likely cost of developing and delivering these resources to the market place?

This report deals directly with the first three of these questions and provides a starting point for analysis of the last two.

To quantify Canada's oil and gas resources potential, the Geological Survey of Canada has developed a methodology in which cumulative probability curves are produced for oil and gas occurrences for various basins, regions or other identifiable areas. The curves are drawn with the knowledge of actual occurrences into which geological judgment is incorporated.

The first phase of the process is the identification of the exploration plays present in a given area. A play consists of a group of prospects and/or discovered fields having common geological characteristics such as source rock, trapping mechanism, etc. Because each factor may vary widely in favourability for hydrocarbon accumulation, their combination in a play provides the possibility for a wide range of values. A play may contain both oil and gas together or separately.

The hydrocarbon potential of individual exploration plays within a sedimentary basin is summed using appropriate statistical techniques.

Estimates prepared in this manner by the Geological Survey of Canada, for six separate geological-geographical regions of Canada are presented in the following pages.

Scope

This report is a summary of the Geological Survey of Canada's current analysis of Canada's oil and gas resources. The summary is drawn from the on-going petroleum resource evaluation program in which the detailed appraisals of individual basins or regions are periodically reviewed. These detailed reviews, are released usually as Open File Reports of the Geological Survey. They contain as many as possible of the petroleum geology data and information that were used in the preparation of estimates. The resource evaluation activity draws extensively from the on-going Basin Analysis Program within the Geological Survey of Canada. This program includes the recording of specialized technical data to produce a variety of reports that synthesize the state of knowledge at a given time.

The style of the summary report is designed to provide current estimates of resources in juxtaposition with brief and generalized comments on the regional setting. Comments are also offered concerning opportunities for future discovery. Those who require more information on any given area are referred to the Open File Report series.

Petroleum resource evaluation activities of the Geological Survey of Canada are focussed primarily on the undiscovered or potential components of conventional oil and gas resources, which is the major emphasis of this report. For the convenience of readers, the authors have compiled data on non-conventional resources from the literature and provincial government agency publications to supplement the Survey's limited studies in this area.

Terminology

The word **resource** as used here includes all oil and gas accumulations known or inferred to exist. **Reserves** comprise that portion of the resource that has been discovered. The word **potential** describes that portion of the resource inferred to exist but not yet discovered. The terms **potential** and **undiscovered resources** are thus synonymous and can be used interchangeably.

The expression **established reserves** is used to describe those reserves which on the basis of identified economic considerations and within a specified time frame, are recoverable with a high degree of certainty from known reservoirs. Because reserves discovered in frontier regions are not fully delineated, and have uncertain economic viability, they do not fit the "established" criteria, and here are expressed as **best current estimates of discovered resources.** The term **remaining reserves** is used here to indicate that remaining portion of a recoverable accumulation not yet produced.

Within this report, gas values given are for marketable or pipeline gas; oil values are given in the SI equivalent of stocktank barrels. For convenience, the unmodified terms **reserves** and **potential** should be read as equivalent to recoverable reserve and recoverable potential. The expression **in-place reserve** is used (in the Non-Conventional Resources chapter) to represent the total volume of oil or gas in a reservoir without consideration of what portion may be recoverable.

Data Base

The Department of Energy, Mines and Resources has had a petroleum resource evaluation program for the past ten years. As data and methodology have evolved the Geological Survey of Canada has prepared successive estimates of Canada's oil and gas resources. The estimates contained in this report are based mainly on data available to the end of 1982 although some information resulting from 1983 exploration programs has been incorporated.

The estimation of the potential of any region depends upon data supplied by industry and government scientists and involves both subjective and objective approaches. Most of the types of data normally used by industry in analyzing exploration plays were available for the preparation of the oil and gas estimates presented here. Data are evaluated in the light of new concepts and hypotheses and in the light of oil and gas occurrences throughout the world.

A resource analysis depends to a considerable degree on the accumulated knowledge concerning the overall framework of the earth's crust, in particular the various sedimentary basins throughout Canada. Such data include the interrelationships of rocks in various areas as well as their geometric configuration. In assessing the potential of an area, the first step is to identify major regions or sedimentary basins of different character. Specialized data are collected then for each region. For example data derived by specialists in geochemistry from the study of the organic material contained in sedimentary rocks provide particularly useful information on the extent and quality of the source rocks within which hydrocarbons may be generated. Such data are fundamental to building an understanding of gas and oil occurrences in a region. Geophysical data such as reflection seismic sections provide a better understanding of the shape, size and character of known and potential oil and gas accumulations. Information on past exploration activity and statistics on any hydrocarbon production is also used in making estimates.

Methodology

The methodology used in petroleum resource evaluation was developed initially to provide the capacity to understand the country's petroleum resources, make economic analyses and project the amounts and costs of future supply from various regions. Initially, the concerns were with the resources of frontier regions which were the least understood geologically. Through time, the concerns have moved to the more conventional resources of Western Canada and, more recently, to quantities recoverable through enhanced recovery processes. As the requirements have changed, so has the methodology. Starting initially from rather simplistic volumetric calculations, the Survey's approach has evolved to what can now be described briefly as a probabilistic methodology conducted at the exploration play level, incorporating both objective data and informed geological opinion. A few years ago, this would have been referred to as the Monte Carlo approach. However, methodology has now advanced well beyond the Monte Carlo stage with more rigorous and more powerful mathematical procedures being incorporated into the system. A characteristic of the approach that remains, however, is the display of estimates in probability terms, usually expressing a range of possible values rather than a single number. Figure 2.1 is an example of a typical curve of estimates which represents the distribution of all possible estimates, given the ranges of all input variables. The curve shown indicates as a minimum expectation that more than 65 million cubic metres of oil are estimated to exist; that on average more than 150 million

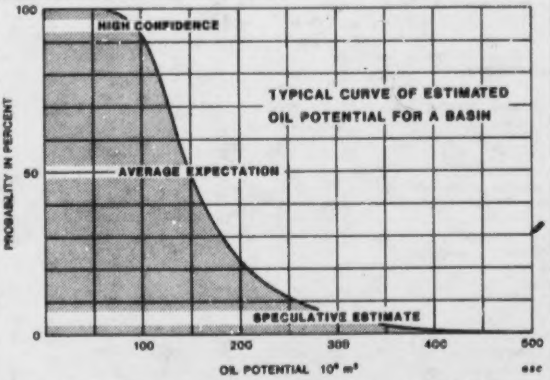

Figure 2.1 Estimate of oil potential for hypothetical basin (cumulative percent probability distribution). Bars indicate values cited in various resource tables

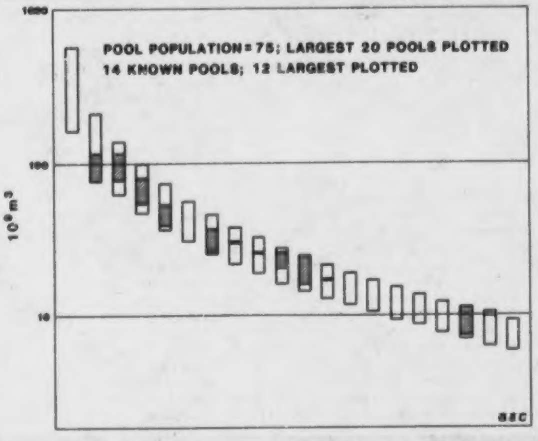

Figure 2.2 Hypothetical pool sizes of play ranked by size. Boxes represent 25 to 75 percent confidence limits. Shaded boxes represent known discoveries

cubic metres may exist; and there is no expectation of more than a value of 480 million cubic metres. As in the case of most real examples, this distribution curve is significantly skewed. Therefore in totalling a number of such curves, only the average expectations can be arithmetically summed. Statistical techniques must be used at other probabilities. There is only one real value for the potential of the basin of course, but it will not be known until the basin is totally explored and produced. The estimate curves change as new data become available and the range of possible values is reduced. For convenience in the report that follows, the full curves are not reproduced, but the three values indicated in Figure 2.1 are tabulated as representative of the current estimates.

In addition to estimates of basin potential, the operating methodology can produce an array of hypothetical pools with attached reservoir characteristics consistent with the input geology and data. One such array is shown in Figure 2.2 in which each bar represents the 25 to 75 percentage probability value for a single pool. This technique provides a useful comparison of predicted pool sizes against the actual results of exploration. In the example given, the discovered pools fit the prediction and suggest that the largest pool has not been found.

The same sets of hypothetical pools can be used also to simulate the results of exploration in terms of cumulative discovery per unit of exploratory drilling. The example shown in Figure 2.3 indicates that about 60 wells would be required to discover 15 billion cubic metres of gas in the basin illustrated. This type of data is particularly useful in the comparison of basinal or regional expectation and as a test of prediction against discovery history.

Economic Considerations

It must be emphasized that these estimates of potential resources, described in terms of probability, are not to be regarded as reserves. In no sense can the estimates be regarded as assured supplies. Firstly, at the time of preparation of the estimate perhaps only a portion of the total resources had been discovered. Secondly, a complex set of economic factors combined with national priorities will determine future rates of discovery, development and production. Investors must be able to anticipate a competitive return, taking into consideration project specific risks. These include reservoir area, well productivity, distance from material supplies, labour, cost of environmental protection and many others. Some other factors include availability of markets at prices adequate to cover the costs of field development and operations. Depending on the point of sale, transportation, particularly from the frontier, can be a significant cost which the resource developer must be able to absorb out of project returns.

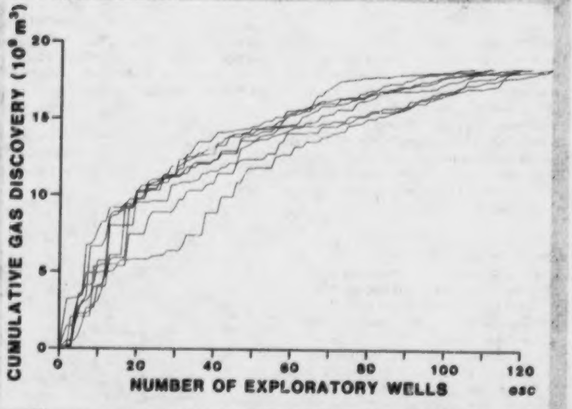

Figure 2.3 **Hypothetical discovery model. Each line represents one computer simulation**

From a national perspective, sufficient benefits must be available from resource development, irrespective of private profitability, to justify the allocation of resources to their exploitation. In this regard, a number of quantifiable and non-quantifiable factors need to be considered. For example, environmental impacts can represent costs to Canada, whereas demonstration of technology with the associated research and development activities which take place can provide other significant benefits for Canada. Although such costs and benefits may not, strictly speaking, be of concern to the private investor they are very much a concern in managing publicly owned resources.

In Canada's conventional producing areas, where a history of development and production is present, assessment of overall economic viability and environmental impact is less complicated in comparison to frontier regions. This is not to say that such assessments can be routinely prepared for major projects in conventional regions. Such decisions require a good deal of effort on the part of the private sector, federal, provincial, municipal governments, regulatory bodies and other interested parties. In frontier regions, however, estimates of capital costs, operating costs, and transportation costs are tentative, bordering on speculative, at this time. Canada has no experience in commercial production and transportation from these areas, which are on the technological frontier in a harsh and sensitive environment.

The Department of Energy, Mines and Resources expects to continue to assess the economics of commercial oil and gas development in various areas of resource potential in an attempt to estimate that portion of potential resources which is likely to fall within the commercial threshold and contribute to Canada's future petroleum supplies. The resource estimates presented in this paper represent a basic data base for such work.

Acknowledgements

The authors have freely drawn on the work of a large number of geologists and on the published literature. Particularly useful sources of information have been supplied from the offices of the Canada Oil and Gas Lands Administration (COGLA), the National Energy Board (NEB), and individuals of the Institute of Sedimentary and Petroleum Geology (ISPG) and Atlantic Geoscience Centre (AGC), Divisions of the Geological Survey of Canada. Special thanks go to R. Conn of the Energy Sector of Energy, Mines & Resources who supplied the comments on economic considerations.

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PETROLEUM REGIONS OF CANADA

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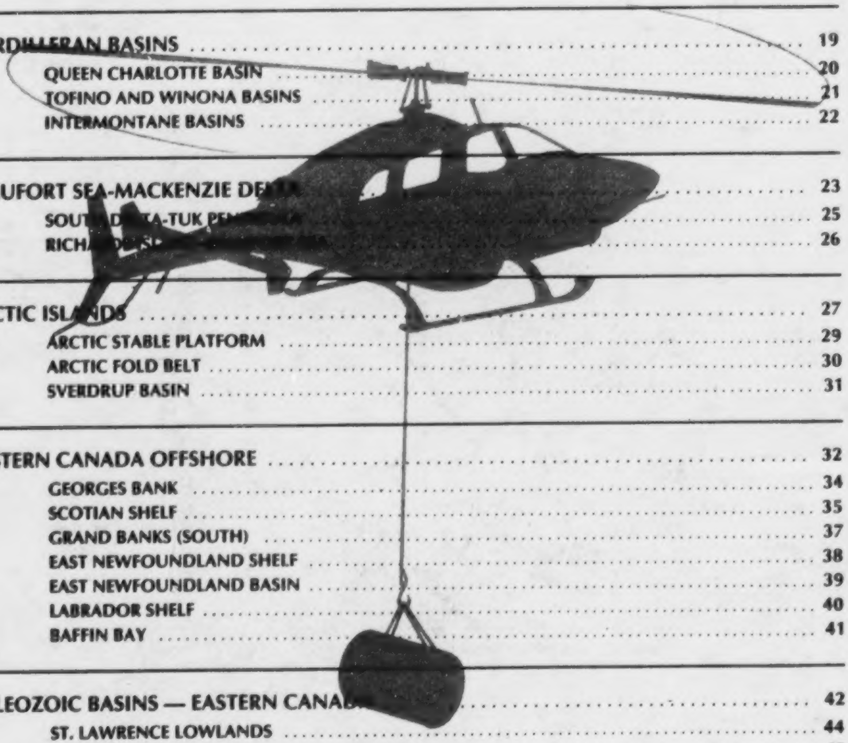

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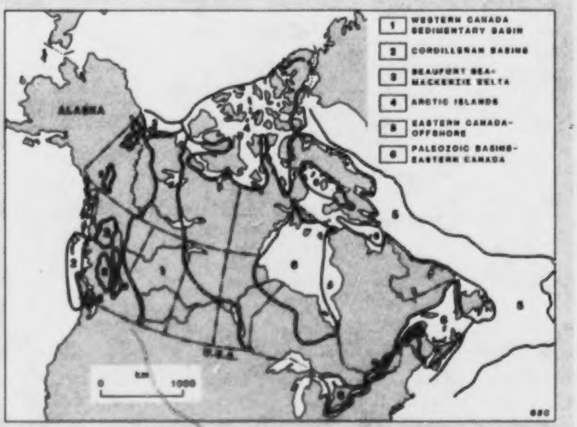
PETROLEUM REGIONS OF CANADA

The oil and natural gas resources of Canada are evaluated on a systematic basis by the Geological Survey of Canada. This report summarizes the current estimates of quantities of oil and natural gas that already have been discovered along with those quantities that are inferred to exist but are not yet discovered. The analysis of resources is made for each of Canada's six petroleum regions (Figure 3.1) addressing both conventional and non-conventional resources with the emphasis on quantifying the undiscovered resources.

Canada is well endowed with natural resources, including oil and natural gas, because of the complex and varied nature of the geology of its landmass and adjacent flooded continental borders. Three major geological settings comprise the framework of Canadian geology. The most complex and oldest rocks are exposed in the vast central region known as the Precambrian Shield, and underlie the structurally stable region known as the craton. Although stable, the craton was covered by shallow seas throughout much of geological time. A thin veneer of sediments deposited in these seas on the craton and over its margins constitutes the sedimentary basins of Canada. Interactions of global tectonic plates resulted in the deformation of these sediments to produce mountain chains around most segments of the edge of the craton. The habitat of oil and natural gas exists primarily in the sedimentary cover of the craton and its margins as well as in those portions of the deformed rocks that have not exceeded the physical limits on preservation of contained hydrocarbons.

Four geological parameters; age (Figure 3.2), facies, structure, and thickness allow the organization of the sedimentary basins into six major petroleum regions. On the following pages of this chapter an attempt is made to inform the reader of the significant characteristics of each of these regions. For each region the initial pages carry a summary of the estimates of the discovered and undiscovered resources. For the reader interested in more detail concerning the geological setting of potential accumulations, a descriptive section is provided for each major element that comprises the region. These sections represent the synthesis of more extensive analyses that have been developed within the Geological Survey of Canada.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2 CORDILLERAN BASINS
3 BEAUFORT SEA-MACKENZIE DELTA
4 ARCTIC ISLANDS
5 EASTERN CANADA-OFFSHORE
6 PALEOZOIC BASINS-EASTERN CANADA
1
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km
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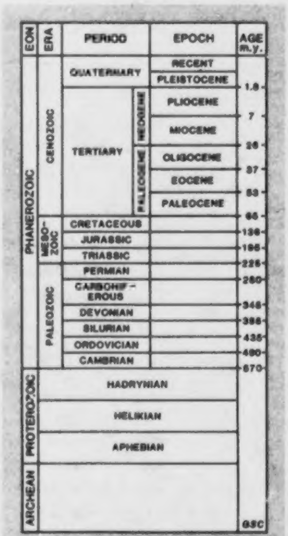
GSC

Figure 3.1 Canada's petroleum regions



EON	ERA	PERIOD		EPOCH	AGE m.y.
PHANEROZOIC	CENOZOIC	QUATERNARY		RECENT	
				PLEISTOCENE	1.8
		TERTIARY	NEOGENE	PLIOCENE	7
				MIOCENE	26
			PALEOGENE	OLIGOCENE	37
				EOCENE	53
				PALEOCENE	65
	MESOZOIC	CRETACEOUS			136
		JURASSIC			195
		TRIASSIC			225
	PALEOZOIC	PERMIAN			280
		CARBONIFEROUS			345
		DEVONIAN			395
		SILURIAN			435
		ORDOVICIAN			490
		CAMBRIAN			570
PROTEROZOIC	HADRYNIAN				
	HELIKIAN				
	APHEBIAN				
ARCHEAN					

GSC

Figure 3.2 Geological time scale

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WESTERN CANADA SEDIMENTARY BASIN

Introduction

The Western Canada Sedimentary Basin is a composite entity of two major westward-thickening, depositional wedges. The older wedge of late Proterozoic, Paleozoic, and early Mesozoic age was deposited on, and outboard of, the ancient North American craton in a passive margin tectonic setting. Both epeirogenic and eustatic events resulted in a number of cratonward converging unconformities, most apparent on the shallow platform, as well as controlled complex facies patterns of deposition of the various stratigraphic assemblages. The second wedge of late Mesozoic and Tertiary age records the change from a passive margin tectonic setting to one of active subduction. The collisions (often oblique), and episodic accretion of arc complexes and small composite terranes tectonically transported the outboard segments of the first wedge upwards and onto the older craton. The tectonic telescoping and thickening of this outer wedge depressed the crust, creating the migrating foredeep to receive the sediments of the clastic wedge eroded from the rising mountains.

Reserves

The remaining recoverable established reserves of oil and gas for the Western Canada Sedimentary Basin are listed in Table II. Oil reserves are concentrated in reservoirs of Devonian age (more than 60% of total) with Cretaceous strata containing about 25% of the total. In part this reflects the better recovery factor of lighter gravity oils from the reef fields (about 45%) compared to a broad range of light to heavy oils of the Cretaceous with an average recovery factor of less than 20%. Oil reserves listed do not include the heavy oils of the Lloydminster type that straddle the Alberta-Saskatchewan border (see Non-Conventional Resources, p. 48). However some heavy oil reserves located south of Lloydminster which are being produced conventionally, are included here.

Estimates of reserves prepared by different agencies commonly vary. This variation reflects different views on the extent and ultimate performance of individual reservoirs, as well as the extent to which proposed secondary and tertiary recovery process expectations have been incorporated. The values for oil reserves listed in Table II exclude enhanced oil reserves that are not fully demonstrated as to technical and economic performance.

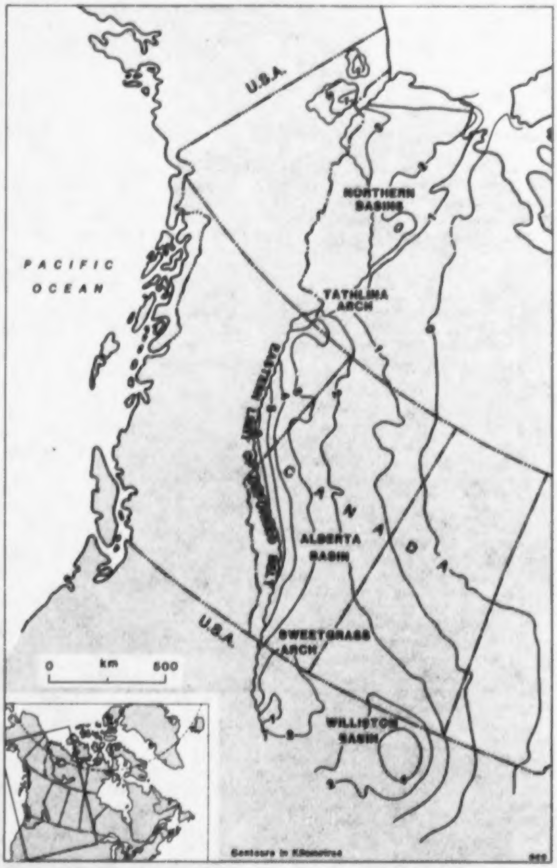

Figure 3.3 Basin fill map of Western Canada Sedimentary Basin. Contour interval in kilometres (after McCrossan and Porter 1973)

Almost half of the gas reserves occur in Cretaceous reservoirs, with Carboniferous and Devonian fields accounting for about 20% each. Sour gas with high hydrogen sulfide content is common in Paleozoic fields in Western Alberta, northeastern British Columbia and the Foothills Belt. More than 80 million tonnes of sulphur have been produced and remaining reserves of sulphur exceed 120 million tonnes. About 10% of remaining reserves of gas occur at shallow depth in relatively poor quality reservoirs at low pressure. Reserves listed in Table II do not include gas trapped in very "tight" reservoirs of the "Deep Basin" of Western Alberta (see Non-Conventional Resources). Table II, however does include reserves that occur in conventional reservoirs within the same area, such as the giant Elmworth Field.

Ethane and Natural Gas Liquids (NGLs) have not been included in Table II but recent estimates indicate remaining gas reserves could also contain more than 300 million cubic metres of ethane and more than 320 million cubic metres of NGLs (propanes, butanes, and pentanes plus).

Potential

The oil and gas potential estimated to exist in the basins of Western Canada are listed in Table III. Although many of the exploration plays for this region are in a mature stage of exploration, several will continue to generate new discoveries. These will tend to be individual pools smaller than those already found and will require a greater level of exploratory effort. New plays and major extensions of existing plays are expected to add most to future discoveries. In spite of the control provided by drilling data, there are still large areas in which deep drilling is so sparse that traps of significant size could have been missed. This is particularly true in south-central Williston Basin, most of southern Alberta and much of west-central Alberta — British Columbia. Geological-geophysical models require refinement for exploration in the prospective Middle Devonian through Carboniferous sequences around the Peace River Arch, the Disturbed Belt in general, and southeastern British Columbia. The Devonian Deep Basin as well as Leduc and Nisku reef patterns on the plains are still not completely understood but will probably yield large to moderate discoveries from traps as yet unseen beneath carbonate shelves that mask the geophysical signals. Future discoveries may include many subtle traps that can best be located by careful reconstruction of the geological history, intensive seismic interpretation, modelling, hydrodynamic considerations and more closely spaced drilling.

Economic and Environmental Considerations

Activity in this area has been primarily in the Alberta Basin where exploration has yielded large discoveries of high quality light oil and heavy oil as well as large quantities of natural gas. Hydrocarbon bearing formations have been found at shallow (1000 metres) to medium (2500 metres) depth. Many of the formations in Northeast B.C. contain sour natural gas which requires additional treatment. The major constraint to future activity is the current lack of natural gas markets.

The Foothills area has higher cost drilling due to higher logistics costs, greater drilling depth, and hard rock formations. Natural gas in the Foothills area tends to be sour, requires special processing, and formations tend to require fracturing. Future activity will be restricted due to the lack of natural gas markets.

Activity in the Northern Basins has not been as intensive as in other areas of Western Canada, with exploration centered around Norman Wells. Some environmental hazards are encountered due to discontinuous permafrost resulting in higher costs.

Comparative drilling costs for parts of Western Canada in 1983 dollars per metre are:

Alberta Basin	$250-300
Williston	$250-300
Disturbed Belt	$550-700
Northern Basins	$250-300

TABLE II
ESTABLISHED REMAINING RESERVES

	OIL 10^6m^3	GAS 10^9m^3
Alberta Basin	600.3	1827.1
Williston Basin	108.4	47.6
Disturbed Belt	0.8	226.6
Northern Basins	44.2*	9.3*
TOTALS	753.7	2110.6

* These values represent fields that are not yet fully delineated, and should be considered as best current estimates of discovered resources rather than established reserves.

TABLE III
OIL AND GAS POTENTIAL (RECOVERABLE)

OIL POTENTIAL (10^6m^3)	High Confidence	Average Expectation	Speculative Estimate
Alberta Basin	160	398	580
Williston Basin	32	95	292
Disturbed Belt	5	15	65
Northern Basins	14	85	415
TOTAL	*234	593	*1210
GAS POTENTIAL (10^9m^3)	**High Confidence**	**Average Expectation**	**Speculative Estimate**
Alberta Basin	1120	1817 ✓	3764
Williston Basin	85	107 ✓	183
Disturbed Belt	255	425 ✓	1305
Northern Basins	42	155	820
TOTAL	*1544	2504	*4930

* These numbers do not add arithmetically but must be summed using statistical techniques

1 m3 = 35.3 ft3

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ALBERTA BASIN

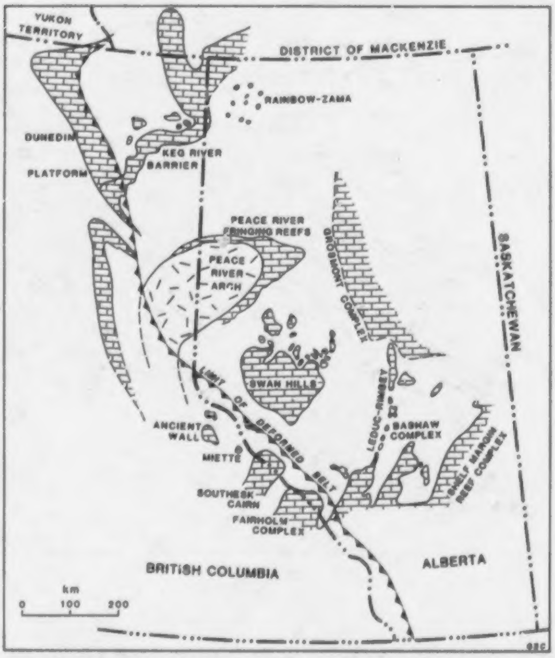


Figure 3.4 Map of major Devonian reef, bioherm, and biostrome complexes. Positions west of deformed belt palinspastically restored

Area 880 000 square kilometres, extending from the 49th parallel to the Tathlina Arch, and from the eastern limit of the disturbed belt eastward to the Precambrian Shield and southwestward to the Sweetgrass Arch.

Geology This Basin which thins from six kilometres near the disturbed belt to a zero edge at the Precambrian Shield consists of two westward thickening sedimentary wedges. The first of mainly Paleozoic rocks was sourced from the east and is dominated by marine carbonate rocks. The second consists mainly of non-marine clastic rocks, derived from the west and of Mesozoic-Cenozoic age.

Earliest Paleozoic rocks consist of Cambrian sandstones, shales, and siltstones, derived from the shield and spread westward over the relatively low relief craton. Ordovician and Silurian deposition consisted largely of shallow water marine carbonates reflecting the most extensive marine transgression of the Phanerozoic, which at its maximum extent in the Late Ordovician, covered most of the North American craton. By the beginning of Middle Devonian time the central Montana Uplift, the Western Alberta Arch, Peace River Arch and the Tathlina Arch were all positive features from which much of the lower Paleozoic rocks had been stripped. The presence of the arches controlled the facies distribution and thickness of sediments from Middle Devonian through Carboniferous time, as transgressive seas encroached from northwest to southeast instead of from the west as earlier. The arches shed sands into the transgressive Devonian deposits and collectively restricted sedimentation to form massive Middle Devonian (Eifelian) salt deposits. The northwest margin of the basin was controlled by a massive reef barrier (Keg River) limiting the southern encroachment of normal marine waters. In successively younger Devonian units there was a progressive southward shift of the barrier reefs and progressively smaller associated salt basins. Frasnian deposition transgressed the Western Alberta Arch and Famennian deposits finally transgressed the crest of the Peace River Arch, re-establishing the marine connection between the cratonic platform and the adjacent continental shelf.

Earliest Carboniferous sedimentation is recorded throughout the basin by a thin dark brown to black, highly organic shale (Exshaw), one of the most persistent markers in the sedimentary column. Overlying shales give way to widespread shallow-water marine carbonates through most of the Early Carboniferous which closed with a series of sandstones and siltstones marking reactivation of most cratonic arches. The Peace River Arch reversed itself in the Early Carboniferous and was moderately subsident; during Late Carboniferous and Permian time it was the site of local foundering where more than 0.6 kilometres of section are preserved in a series of grabens. Most of the basin was emergent at the close of the Permian. An early Triassic transgression resulted in a sequence of dark shales, overlain by phosphatic shales and a regressive sandstone (Halfway) of Middle Triassic age. The Late Triassic consists of shallow water evaporitic carbonates and anhydrites overlain by thick bioclastic limestones. Much of the Triassic was removed by pre-Jurassic erosion, and uppermost units are present only in northeastern British Columbia.

Lower and Middle Jurassic rocks are mainly marine shales, with minor sandstones which are transitional to Upper Jurassic non-marine sandstones and shales of the Kootenay and Nikinassin formations. This marks the beginning of the Mesozoic-Cenozoic sedimentary "wedge" that formed in response to orogenic activity to the west. Uplift supplied continental sediments that spread eastward across the basin at about the same time that marine seaways advancing from the north and south joined to form a narrow seaway extending from the Arctic to the Gulf of Mexico in the middle Cretaceous. Renewed orogenic activity in Late Cretaceous and Paleocene resulted in extensive non marine clastic sediments that covered the entire basin.

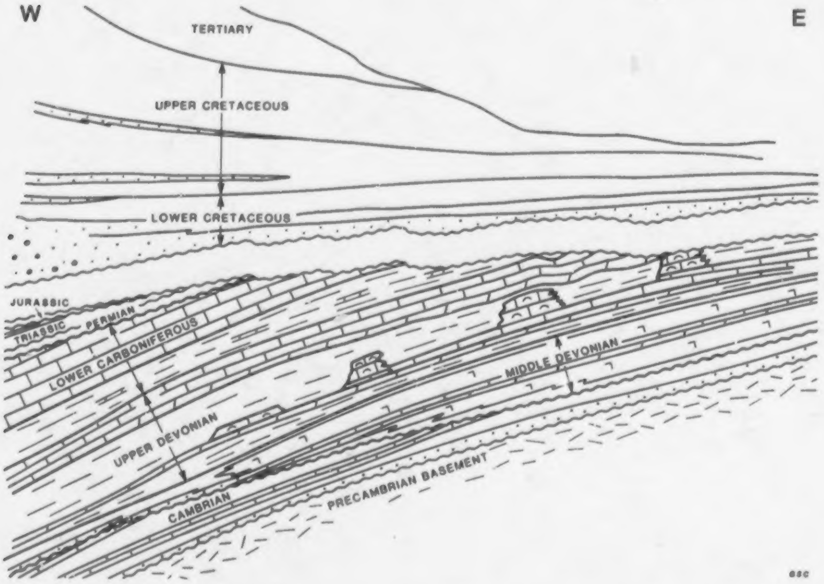


Figure 3.5 Generalized stratigraphic section of Alberta Basin. Figure separated to emphasize the Foreland Basin

Drilling History The first commercial gas field was discovered in 1904 at Medicine Hat in Upper Cretaceous rocks. Major exploration for oil followed the Devonian Leduc reef discovery in 1947. In total, more than 100,000 wells have been drilled in the basin.

Potential Source Rocks Potential source rocks are abundant throughout the section, particularily the dark shales of the Devonian, Carboniferous and Mesozoic. Thermal maturity ranges from immature in the shallow gas areas of the northern and eastern parts of the basin, to overmature in the deeper parts of the basin adjacent to the disturbed belt.

Potential Reservoir Rocks Good quality reservoir rocks are common throughout the section. Traditionally, the most important reservoirs have been the biogenic carbonates of the Devonian (bioherm and biostrome complexes of Figure 3.4); the subcrop edge of Devonian and Carboniferous units at the pre Jurassic unconformity; and the extensive basal and transgressive-regressive sandstones of the Cretaceous. Other prolific reservoir units include the Paleozoic transgressive sands surrounding the Peace River Arch and Triassic carbonates of northeastern British Columbia.

Known and Potential Hydrocarbon Occurrences More than 9,000 gas and 3,000 oil pools are identified within the Alberta Basin. Remaining established reserves are estimated to be 600 million cubic metres of oil and 1827 billion cubic metres of gas. Production to date has been approximately 1400 million cubic metres of oil and 1000 billion cubic metres of gas. For oil, about 65% of the reserves are in Devonian reservoirs and over 20% in the Cretaceous. For gas, about 50% of the reserves have been found in Cretaceous reservoirs and about 35% in the Devonian. Potential oil and gas occurrences are estimated to occur throughout the section but greatest opportunities will be in deeper (and older) rather than shallow horizons.

WILLISTON BASIN

Area Approximately 565 000 square kilometres (Canadian portion of Basin).

Geology The Williston Basin consists of relatively unstructured Paleozoic clastic and carbonate rocks largely derived from the Precambrian Shield that were beveled at the close of Paleozoic time, overlain by the westward derived Cretaceous-Tertiary clastic wedge. The basin was established by Middle Ordovician time when a series of cratonic arches rose to circumscribe the basin. Early sediments are clean Cambro-Ordovician sandstones derived from Cambrian sandstones from those arches as well as from Proterozoic sandstones from the Canadian Shield. Widespread thin, shallow-water shelf carbonates dominate the section from Late Ordovician to Late Silurian, extending from the Shield to central Montana. These rocks subsequently were deeply eroded in pre-Middle Devonian time due to strong uplift of surrounding arches, producing the prominent north facing Meadow Lake Escarpment (250 m high) which acted as a barrier in front of which thick salt deposits of Middle and Late Devonian age were deposited. Latest Devonian and Early Carboniferous successions consist of restricted euxinic shales overlain by open marine calcareous shales and limestones. The limestones that are crinoidal in the western part of the basin grade eastward to an evaporitic facies of dolomite and anhydrite. By the close of Carboniferous time, the evaporitic sequences extended to the centre of the basin. During Permian, Triassic and Early Jurassic time, the basin was isolated by uplift of its bordering cratonic arches and eroded at the margins. During this period the Sweetgrass Arch became prominent, effectively separating the normal shallow-water marine sedimentation of the Alberta Basin from the restricted red beds and minor salt deposits of the Williston Basin.

Since Late Jurassic the synorogenic clastic wedge spread eastward across all of the Western Canada Sedimentary Basin, initially with non-marine to marine shale and sandstone sequences; giving way to essentially non-marine clastic facies of the Paleocene to complete the depositional history of the basin.

Drilling History Although more than 20,000 wells have been drilled in the area, they have been concentrated in the producing areas. Much of the prospective area has yet to be tested by drilling.

Potential Source Rocks Winnipeg, Bakken, Exshaw, Jurassic and Cretaceous shales.

Potential Reservoir Rocks Potential reservoir rocks are common throughout the section including Cambro-Ordovician sandstones, Early Carboniferous carbonates of eastern and central parts of the basin, and Jurassic-Cretaceous sandstones.

Known and Potential Hydrocarbon Occurrences The most important oil accumulations are associated with the eroded Carboniferous subcrop belt of southeastern Saskatchewan and in southwestern Manitoba where more than 120 pools contain over 300 million cubic metres of recoverable oil. Major fields include Weyburn, Midale, and Steelman. The second most important group of fields produce gas and oil from Middle Jurassic Shaunavon and upper Jurassic-basal Cretaceous Roseray and Cantuar Formations, in a 200 kilometre long belt in southwestern Saskatchewan. These deposits are combined stratigraphic-structural traps associated with the western margin of the basin. Oil production is obtained also from Bakken sandstones. Extensive, shallow, low pressure gas reserves and potential occur along the western margin of the basin in Milk River - Medicine Hat sands. The most recent oil discoveries have been in southwest Manitoba where red beds of Triassic-Jurassic age overlie the Carboniferous subcrop (Waskada field).

Additional potential is anticipated in lower Paleozoic sandstones and dolomites, Devonian carbonates, as well as in the established reservoir units.

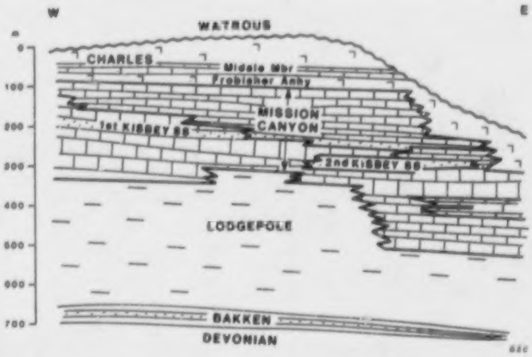


Figure 3.6 Detailed facies relationships of the Carboniferous stratigraphy of the Williston Basin that will result in stratigraphic traps (after Edie 1958)

DEFORMED BELT

Area 193 000 square kilometres, approximately 40 000 square kilometres in the Foothills in a linear belt extending 1000 kilometres northerly from the United States border at Waterton to the Southern District of Mackenzie.

Geology Like the adjacent plains, the stratigraphic record of the Deformed Belt consists of two westward thickening sedimentary wedges. The older, dominantly marine, Paleozoic and early Mesozoic wedge is the continuation of that of the adjacent plains. However, it contains the transition from platformal sediments of the plains to the equivalent, though much thicker successions of the miogeocline. Additionally much of the succession missing at unconformities in the plains is still preserved in the Deformed Belt permitting a fuller reconstruction of the paleogeography. The second major wedge of late Mesozoic and Cenozoic age constitutes the clastic wedge shed eastward into a migrating foredeep that formed in response to the loading imposed by the rising and telescoping of the mountains. Much of the earlier deposits of the clastic wedge were themselves cannibalized and redeposited into younger, eastern parts of the foredeep. Structurally, the Disturbed Belt consists of two major elements, the Rocky Mountains and the Rocky Mountain Foothills. Only the latter has seen significant exploration activity. Structures are typical of "thin-skinned" deformation, nevertheless, regionally a wide variety of styles are developed within that framework. Imbricate thrusts dominate the southern area (Figure 3.7) whereas blind thrusts and folds (Figure 3.8) are dominant in the northern areas.

Drilling History The first oil well drilled in Western Canada was drilled in 1902 at Oil City which is now within Waterton National Park. Since then numerous major oil and gas fields have been discovered from Waterton in the south to Beaver River in the northern part of the belt. The belt nevertheless has not been intensively drilled because exploration is expensive, seismic difficult, and most of the gas is sour, corrosive, and environmentally hazardous.

Potential Source Rocks Dark marine shales of Devonian and Mississippian age are the major source rocks in the south. A variety of similar Paleozoic and Mesozoic rocks occur in the north. Current maturation studies suggest the possibility of lesser levels of maturity in the western portions than has been conventionally accepted.

Potential Reservoir Rocks The main reservoir rocks occur in Mississippian and Cretaceous sequences in the south whereas major Devonian and Triassic reservoirs occur as well in the northern Foothills. Porosity is commonly reduced because of deeper burial, however, fractured reservoirs are common.

Known and Potential Hydrocarbon Occurrences The remaining established reserves are 226.6 billion cubic metres of gas and 0.8 million cubic metres of oil. Because much of the gas is sour and must be processed, sulphur has become a significant commercial byproduct. Compared with the other parts of the Western Canada Sedimentary Basin, the Disturbed Belt has a very low drilling density, many plays remain untested.

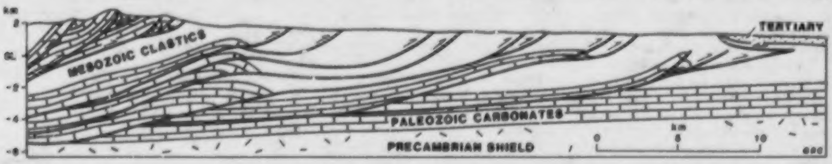


Figure 3.7 **Generalized structure section of southern Alberta Foothills. Thrusting dominates folding (after Bally *et al* 1966)**

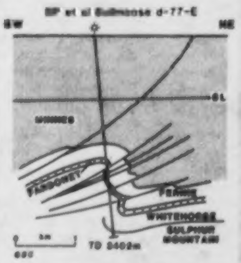


Figure 3.9 **Structure section, Bullmoose Field, Northeastern British Columbia (after Barss and Montandon 1981)**

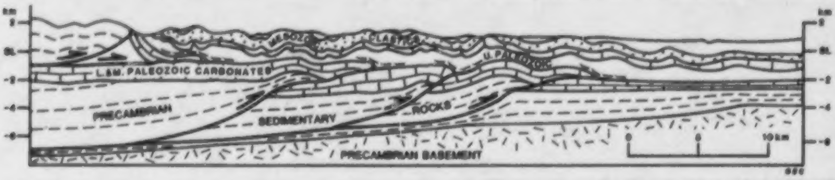


Figure 3.8 **Generalized structure section of northern British Columbia Foothills. Blind thrusts and folds dominate**

NORTHERN BASINS

Area Approximately 490 000 square kilometres. About 30 000 square kilometres of this total lies west of the Richardson Mountains in the Eagle Plain and Old Crow Basins.

Geology The northern extension of the Western Canada Sedimentary Basin is usually discussed as a series of separate basins or physiographic regions (Figure 3.10). These include the Anderson Plain, Mackenzie Plain, Peel Plain and Peel Plateau, plus the Eagle Plain and Old Crow Basins to the west of the Richardson Mountains. However, in simple terms, the whole area is somewhat analogous to the Alberta basin, in that the total section consists of two major wedges of sedimentary rocks separated by a major unconformity surface.

The lower wedge consists of platformal rocks, dominantly marine carbonates, which persist from Early Cambrian through Middle Devonian. This carbonate and shale sequence, which is broken by several regional unconformities, was derived from the Precambrian Shield and thickens to about 3000 metres at the outboard margin of the craton. Lower Cambrian deposits are widespread in the Peel Plateau area. In deeper parts of the region (Figure 3.11), the carbonate sequences pass laterally into black graptolitic shales. Middle Devonian reefs (Figure 3.12) were developed in the Mackenzie Plain area and in the Eagle Plain Basin. Upper Devonian rocks of the Eagle Plain Basin include clastics shed from uplifts to the north with deposition continuing into the late Paleozoic times. Elsewhere, late Paleozoic rocks are largely missing or were not deposited since most of the area was above sea level. Late Jurassic marine shales mark the beginning of a major transgression, and thick Lower Cretaceous basal sandstones and shales are present over much of the area. Upper Cretaceous and Tertiary rocks, that were derived mainly from Laramide uplift to the west and south were mainly removed as the Mackenzie River drainage system developed.

Drilling History The earliest drilling resulted in the discovery of the Norman Wells oil field in 1920. Since then about 150 wells have been drilled in the area, most of them since 1960. There are 24 wells drilled in Eagle Plain Basin but none in the Old Crow Basin.

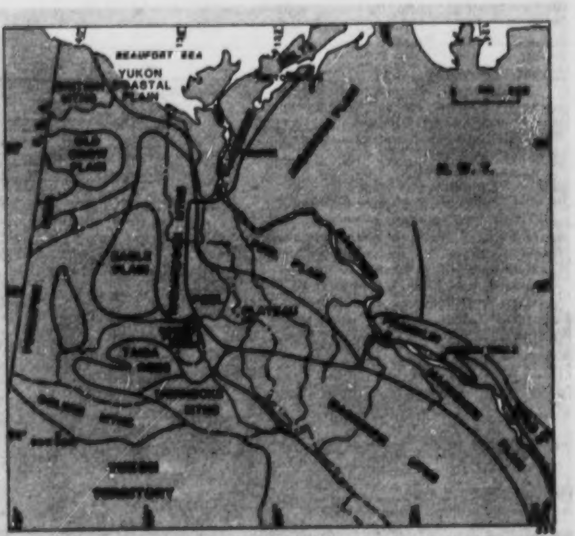

BEAUFORT SEA
YUKON COASTAL PLAIN
OLD CROW PLAIN
EAGLE PLAIN
N.W.T.
YUKON TERRITORY

Figure 3.10 Physiographic subdivisions of the Northern Basins (after Kunst 1973)

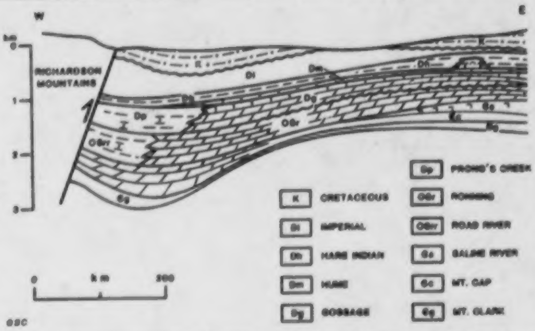

W
E
km
0
1
2
3
RICHARDSON MOUNTAINS
K
Di
Dm
Dh
Dg
Dp
OGr
OSr
Gs
Gc
Gg
K CRETACEOUS
Di IMPERIAL
Dh HARE INDIAN
Dm HUME
Dg GOSSAGE
Dp PRONG'S CREEK
OGr RONNING
OSr ROAD RIVER
Gs SALINE RIVER
Gc MT. CAP
Gg MT. CLARK
0
km
200
GSC

Figure 3.11 Schematic stratigraphic section across Peel Plateau (after Kunst 1973)

Potential Source Rocks Potential source rocks exist in shales of both Paleozoic and Cretaceous age, including the Ordovician to Devonian graptolitic shales and bituminous shales of the Middle and Upper Devonian. Proterozoic shales also may provide hydrocarbons in the Peel Plateau area.

Potential Reservoir Rocks The most prospective reservoir rocks have been the biohermal facies of Middle Devonian age. Several sandstones of Cambrian, Carboniferous, Permian and Cretaceous age are also potential reservoir rocks.

Known Hydrocarbon Occurrences The Norman Wells oil field is the largest discovery in the region and is estimated to contain about 40 million cubic metres of recoverable oil. There have been two gas, and one gas and oil discoveries in Carboniferous sandstones in the Eagle Plain Basin. At Tedji Lake, a gas discovery in Cambrian sandstones is estimated to contain about 2.5 billion cubic metres.

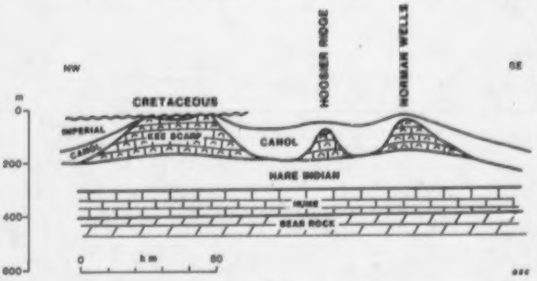

NW
SE
HOOSIER RIDGE
NORMAN WELLS
m
0
200
400
600
CRETACEOUS
IMPERIAL
KEE SCARP
CANOL
CANOL
HARE INDIAN
HUME
BEAR ROCK
0
km
50
GSC

Figure 3.12 **Stratigraphic relationships of the Devonian Kee Scarp reefs**

CORDILLERAN BASINS

Introduction

Recent concepts envisage the Cordillera as the product of continental collision between North America and at least two other terranes. Docking of these exotic terranes during Jurassic and Cretaceous time produced the sutured tectonic welts of metamorphic and plutonic rocks that subdivide the Cordillera and produced the tectonic telescoping and thickening of the Rocky Mountain deformed belt. Thus the later Mesozoic and Tertiary successor basins of the Intermontane region are underlain by varied sequences that originated outside of the North American paleogeographic context.

Unlike the other coastal regions of Canada, the West Coast is a tectonically active plate margin where subduction and large scale translation of the earth's crust has, and is taking place. The British Columbia Offshore region is located in the Insular Tectonic Belt which like most of British Columbia is composed of allocthonous terranes that have been accreted to the western margin of the ancestral North American Plate. Prospective areas for petroleum occur in sedimentary sequences that were deposited as portions of the exotic terranes prior to accretion; in melange and foredeep assemblages in response to collision and suturing; and in postsuturing basins in response to continued subduction.

TABLE IV
OIL AND GAS POTENTIAL
WEST COAST OFFSHORE

	High Confidence	Average Expectation	Speculative Estimate
OIL POTENTIAL (10^6m^3)		50	110
GAS POTENTIAL (10^9m^3)	40	270	760

Reserves and Potential

No reserves have been discovered in this region, and estimates of potential have not yet been prepared for the Intermontane Basins. Based on limited available geochemical evidence, the Intermontane Basins are considered unlikely to contain significant oil potential. The thermal metamorphism associated with these basins suggests that relatively small quantities of dry gas potential may exist, although other authors have estimated that about 150 billion cubic metres of gas potential might be appropriate.

For the westcoast offshore basins, estimates of potential are listed in Table IV. The more prospective areas for petroleum are located primarily on the Wrangellia Terrane with local overlap onto portions of the Alexander Terrane to the north, and the Olympic and Pacific Rim Terranes to the south. Two large sedimentary basins are known — the Queen Charlotte Basin lying between the Queen Charlotte Islands and the Mainland, and the Tofino Basin lying off the west coast of Vancouver Island. There is also the small Winona Basin on the continental slope off northern Vancouver Island, and the larger though shallow Nanaimo Basin lying between Southern Vancouver Island and the Mainland. The Tertiary sections of both Queen Charlotte and Tofino basins have been tested by a number of wells but with no success. Due to environmental constraints there has been no drilling in the offshore since 1969. Many of the play concepts, particularly those conceived to be beneath the Tertiary sedimentary cover, have yet to be tested by drilling, therefore the estimates presented here reflect a high degree of uncertainty common to many frontier areas.

QUEEN CHARLOTTE BASIN

Area The region comprises approximately 50 000 square kilometres, and includes the areas underlying Queen Charlotte Sound, Hectate Strait and Dixon Entrance on the continental shelf out to a depth of water bounded by the 200 metre isobath.

Geology Above an economic basement of Triassic age Karmutsen volcanics is a thick, mainly marine sequence of volcanoclastic sands, shales, limestones and siltstones of Jurassic age. Faulted, folded and locally eroded, they are overlain by clastics of both Early and Late Cretaceous age. Both sequences were again subjected to faulting and folding in Late Cretaceous time. Thick volcanics of the Masset Formation unconformably overlie the succession in the northwest and interfinger laterally with the lower part of the thick Tertiary clastics. A major depocentre of the post-suture sediments of the Miocene Skonun Formation overlies a rift in southern Queen Charlotte Sound where sediment thicknesses of 4500 metres are reported.

Drilling History In 1915, British Columbia Coal Company drilled a shallow (490 m) well on Graham Island. Royalite drilled the onshore Queen Charlotte well (1006 m) in 1950. Richfield drilled six onshore shallow (all less then 2500 m) wells on Graham Island during 1958-1961. Between 1967 and 1969, Shell Canada drilled fourteen offshore wells testing Tertiary plays, eight of which were located in Queen Charlotte region.

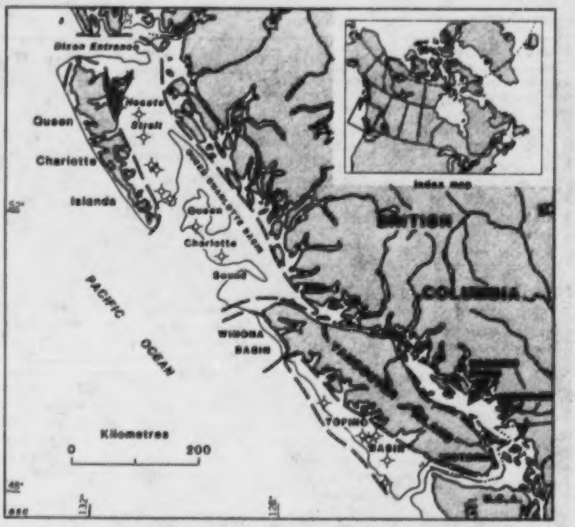

Dixon Entrance
Hecate
Strait
Queen
Charlotte
Islands
Queen
Charlotte
Sound
QUEEN CHARLOTTE BASIN
PACIFIC
OCEAN
WINONA
BASIN
TOFINO
BASIN
BRITISH
COLUMBIA
U.S.A.
Index map
Kilometres
0
200
52°
48°
132°
128°
GSC

Figure 3.13 Location map of west coast British Columbia basins

Potential Source Rocks Organic rich shales of the Jurassic Kunga and Maude Formations are known to have generated oil, some of which has migrated from the source beds. Carbonaceous marine shales are known to occur in the Cretaceous Queen Charlotte Group. Within the Tertiary sequences lignites occur in the Skonun Formation, however, most of the Tertiary section is considered to be thermally immature.

Potential Reservoir Rocks Sandstones are common in much of the pre-Cretaceous allocthonous and suture assemblages, however many are volcanoclastic in origin with consequent restricted porosities and permeabilities. The Cretaceous sequence contains several good clean marine sandstones. Tertiary sandstones have good measured porosities but the feldspar rich sandstones have variable to poor permeabilities.

Known Hydrocarbon Occurrences Oil staining was reported from the offshore Sockeye B-10 well. Gas was flared from an early (1915) onshore well in the Queen Charlotte Islands. Tar filled vesicles occur in the Masset volcanics and also in the Middle Jurassic Yakoun Formation.

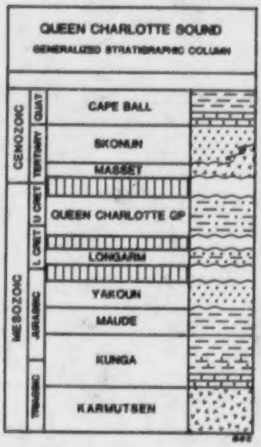

QUEEN CHARLOTTE SOUND
GENERALIZED STRATIGRAPHIC COLUMN
CENOZOIC
QUAT
TERTIARY
MESOZOIC
U CRET
L CRET
JURASSIC
TRIASSIC
CAPE BALL
SKONUN
MASSET
QUEEN CHARLOTTE GP
LONGARM
YAKOUN
MAUDE
KUNGA
KARMUTSEN
GSC

Figure 3.15 Queen Charlotte Sound

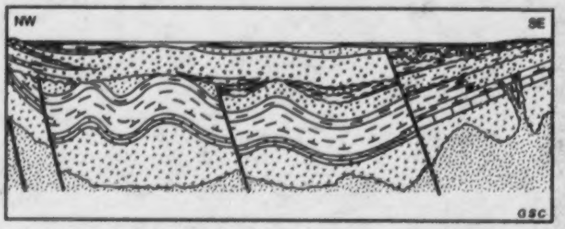


Figure 3.14 Schematic stratigraphic section across Queen Charlotte Sound

TOFINO AND WINONA BASINS

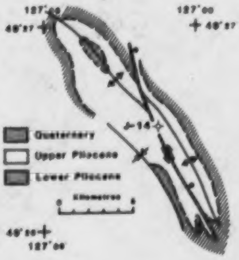
Area The Tofino Basin underlies an area of the continental shelf and slope off Vancouver Island of approximately 9000 square kilometres inboard of the 200 metre isobath (Figure 3.13). The Winona Basin underlies an area of the continental shelf and slope off northern Vancouver Island of approximately 5000 square kilometres most of which lies outboard of the 200 metre isobath.

Geology Thick (4000 metres) sections of low velocity sediments have been identified by seismic profiling in both the Tofino and Winona Basins. Drilling in the Tofino Basin has confirmed the late Tertiary age of these sediments. The sediments unconformably overlie early Tertiary and Mesozoic deformed volcanic, plutonic, and sedimentary rocks. The Neogene sediments form a relatively undeformed wedge which thickens seaward from Vancouver Island to the base of the continental slope. The sediments include mainly marine, poorly consolidated, calcareous mudstones and minor siltstones of Miocene to Pliocene age. Sandstones occur near the base of the succession. Large low amplitude structures occur, that are products of both subduction related tectonics and, or as a gravity induced response to overpressuring and diapiric movement of the shales.

The thick sediments of the Winona Basin have not yet been penetrated by drilling, as the major portion of the basin occurs beneath very deep water. Mudstone, sandstone conglomerate and minor coal have been dredged from canyon walls of the continental slope above the main portion of the Basin. The sediments form a wedge dipping seaward under the continental shelf and slope, outboard of which, they are downfaulted into very deep water. Deformation in the deep water segment of the basin is seen on seismic near the base of the slope and beneath Winona Ridge located in deep water 110 kilometres offshore (See Figure 3.18)

Drilling History Shell Canada drilled six offshore wells testing the Tertiary sediments of Tofino Basin in the period 1967 to 1969. Recently there has been a moritorium on drilling in the waters offshore of British Columbia because of environmental considerations.

Potential Source Rocks Good source rocks have yet to be identified in the Neogene succession. All the fine clastics are light grey colored, organic poor mudstones.

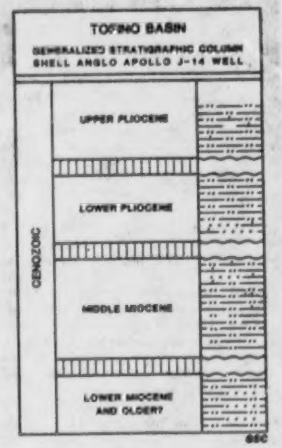


127°00
48°27
127°00
48°27
J-14
▨ Quaternary
☐ Upper Pliocene
▨ Lower Pliocene
0
Kilometres
48°20
127°00

Figure 3.17 Exposed sea-floor structure, Apollo anticline (after Yorath 1980)

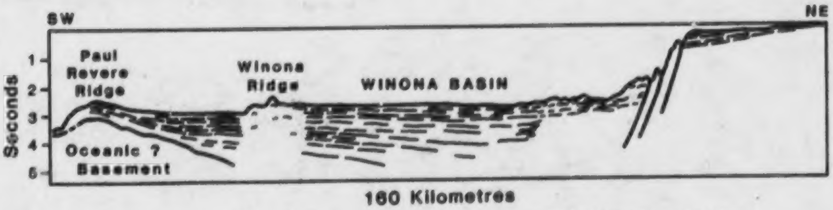
Potential Reservoir Rocks Good porosity and permeabilities have been measured in the sidewall cores from the exploratory wells. The better reservoir sandstones occur near the bottom of the succession.

Known Hydrocarbon Occurrences Minor gas shows were encountered in shallow zones in the Pluto I-87 and Prometheus H-68 wells in the Tofino Basin. Gas logging obtained relatively high methane values and C_3 through C_5+ values generally increased in the deeper and older Tertiary sediments.



TOFINO BASIN
GENERALIZED STRATIGRAPHIC COLUMN
SHELL ANGLO APOLLO J-14 WELL
CENOZOIC
UPPER PLIOCENE
LOWER PLIOCENE
MIDDLE MIOCENE
LOWER MIOCENE AND OLDER?
GSC

Figure 3.16 Tofino Basin



SW
NE
Seconds
1
2
3
4
5
Paul Revere Ridge
Winona Ridge
WINONA BASIN
Oceanic ? Basement
160 Kilometres

Figure 3.18 Schematic structure section (seismic) Winona Basin (after Chase *et al* 1975)

INTERMONTANE BASINS

Area 240 000 square kilometres; distributed among four major basins (Figure 3.19), the Whitehorse, Bowser, and Nechako Basins (including the Tyaughton Trough) and the Quesnel Trough.

Geology Lower Paleozoic carbonates and equivalent deep water siliceous shales overlie altered volcanic assemblages in most of the Intermontane Basins and contain exotic faunas relative to North America. Commonly overlain by Triassic carbonates and arc-type volcanics which also have been interpreted as exotic, they are, in turn, overlain by Jurassic synorogenic clastics believed to be the product of the accretionary collision. Another generation of coarse clastics of middle to Late Cretaceous age is the result of a second major accretion of terranes to the western margin of North America. The basins were strongly folded and faulted during each accretionary event. Total thickness of the sediments may have exceeded 12 000 metres prior to structural elevation and erosion in some of the basins. Late Tertiary to Recent volcanism has capped the Nechako Basin (Figure 3.20) obscuring the underlying geology.

Drilling History One well has been drilled in the Bowser Basin and four wells drilled in the Nechako Basin. Other basins are untested.

Potential Source Rocks Most of the basins contain coals or carbonaceous sandstones and the sediments are thought to contain mainly terrestrially derived organic material. All demonstrated very high levels of thermal maturity so that only overmature gases should be expected.

Potential Reservoir Rocks Sandstones are widespread within the various depositional sequences. Most were deposited as immature sediments whose porosity and permeability have been reduced by later alteration.

Known Hydrocarbon Occurrences A minor show of dry gas was recorded in the Bowser Basin well.

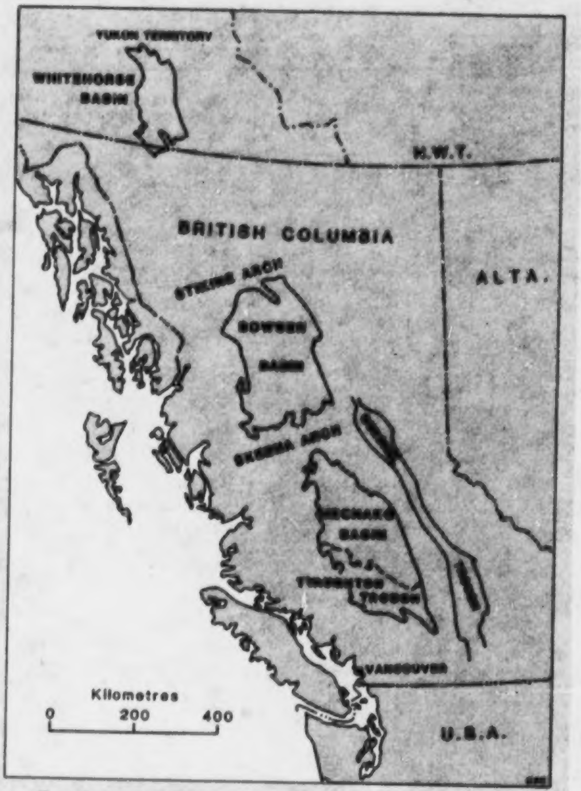

YUKON TERRITORY
WHITEHORSE BASIN
N.W.T.
BRITISH COLUMBIA
STIKINE ARCH
ALTA.
BOWSER BASIN
SKEENA ARCH
NECHAKO BASIN
TYAUGHTON TROUGH
VANCOUVER
Kilometres
0
200
400
U.S.A.

Figure 3.19 Location map of Intermontane Basins (after Koch 1973)

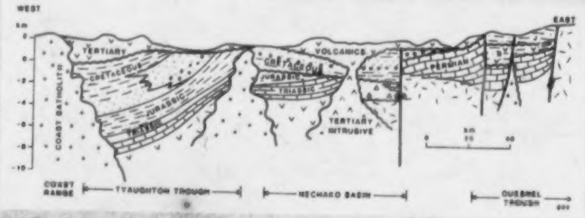

WEST
EAST
km
0
-2
-4
-6
-8
-10
COAST BATHOLITH
TERTIARY
CRETACEOUS
JURASSIC
TRIASSIC
VOLCANICS
CRETACEOUS
JURASSIC
TRIASSIC
TERTIARY INTRUSIVE
PERMIAN
km
0
20
40
COAST RANGE
TYAUGHTON TROUGH
NECHAKO BASIN
QUESNEL TROUGH

Figure 3.20 Schematic section from Tyaughton Trough to Quesnel Trough (after Koch 1973)

BEAUFORT SEA-MACKENZIE DELTA

Introduction

This region includes the onshore Mackenzie Delta, Tuk Peninsula and that part of the offshore extending to the edge of the continental shelf at a water depth of approximately 200 metres. This region is arbitrarily terminated to the northeast in the middle of Amundsen Gulf. The region is underlain by deltaic sandstones and shales of Mesozoic and Cenozoic age which thicken rapidly to more than 12 000 metres a short distance seaward from the present delta. These beds overlie faulted Paleozoic rocks stepping down steeply beneath the Mesozoic-Cenozoic cover. The Paleozoic rocks rise to the surface and are exposed in the southern part of the area. The basin contains a series of Mesozoic-Cenozoic depocentres. The thick Upper Cretaceous to Holocene clastics were deposited in a series of migrating deltaic wedges which built out over the passive type continental margin of the southern Beaufort Sea.

Reserves

Quantities of oil and gas discovered to date are listed in Table V. The values given are described as "best current estimates" of "discovered resources" rather than the more conventional terminology of "remaining established reserves" because for most of the discoveries, the nature and total extent of the reservoirs is poorly defined. In addition to a general lack of delineation drilling, there are many reasons for the wide spectrum of "reserve" estimates that exist for

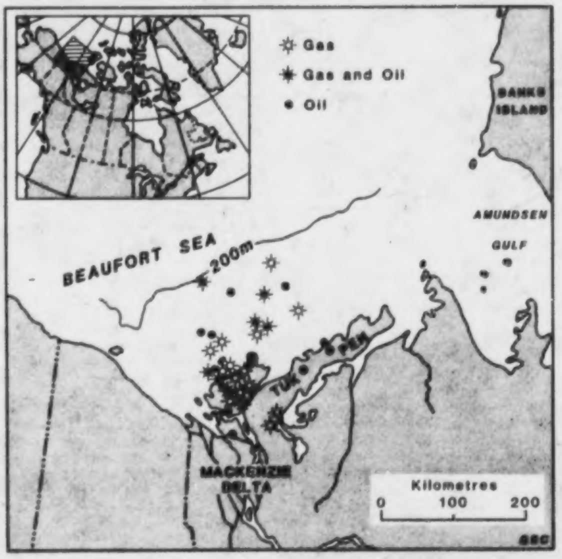

Gas
Gas and Oil
Oil
BANKS ISLAND
AMUNDSEN GULF
BEAUFORT SEA
200m
TUK PEN
MACKENZIE DELTA
Kilometres
0
100
200
GSC

Figure 3.22 Oil and gas discoveries, Beaufort Sea-Mackenzie Delta

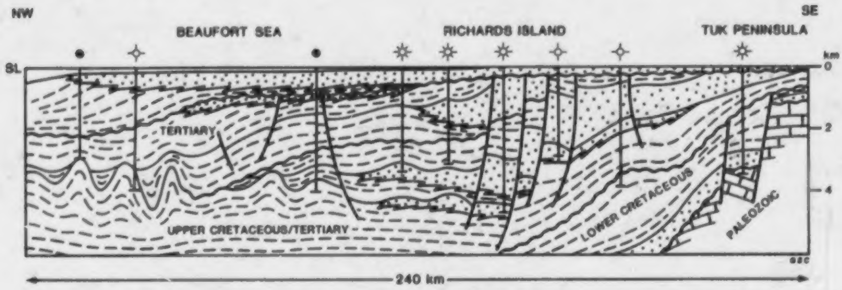

NW
SE
BEAUFORT SEA
RICHARDS ISLAND
TUK PENINSULA
SL
km
0
2
4
TERTIARY
UPPER CRETACEOUS/TERTIARY
LOWER CRETACEOUS
PALEOZOIC
GSC
240 km

Figure 3.21 Schematic stratigraphic relationships, Beaufort Sea-Mackenzie Delta

this region, particularily those for the discoveries in the Beaufort sea. Unlike other frontier regions, many of the reservoirs here are usually poorly characterized by mechanical logs, are of poor to fair quality with questionable lateral continuity, do not have definitive drillstem testing and are not easily defined by seismic. The values expressed in Table V are an attempt to quantify what can be considered to exist with some reasonable confidence, amplified by geological-geophysical judgement as to lateral and vertical continuity. As such, they are conservative, and certainly subject to significant change.

Potential

The Beaufort Sea-Mackenzie Delta region is estimated to contain 1347 million cubic metres of oil and 1865 billion cubic metres of gas (average expectation) as shown in Table VI. Speculative estimates are almost 3000 million cubic metres of oil and over 4000 billion cubic metres of gas. These are high estimates for a relatively small region but not inconsistent with the high success rate and the early discovery of three near giant gas fields (85 billion cubic metres). The largest potential for both oil and gas is estimated to exist in the Beaufort Sea area, both in the part now being evaluated by drilling, and in the large part of the area westward to the Canada-United States boundary. The latter area is virtually untested but is known from seismic exploration to contain similar features to those of the main delta area. Within the area which has been the main focus of activity in recent years, there are many structures that have only been tested on the crest. Flank pinch-out plays, traps against faults and many others still require evaluation, as do the numerous stratigraphic plays associated with deltaic sedimentation.

Economic and Environmental Considerations

For purposes of economic evaluation, the Beaufort Sea area can be subdivided primarily in relation to water depth. The shallow areas, in depths less than approximately 20 metres, allow the construction of artificial islands. In greater water depths, platforms are required. In either offshore case, development systems will have to be able to withstand ice pressures, and transportation lines will have to be buried, or protected in some other manner, from ice to allow year-round operations. Although work has been done in the design of systems to permit year-round production and transportation from the Beaufort Sea, the technology is largely still untried.

Onshore, in the South Delta-Tuk Peninsula, development costs are potentially less than in the Beaufort Sea, although still substantially higher than those in the Western Provinces. Here, as in the Beaufort Sea, low temperatures combined with the long period of darkness leads to lower working efficiencies. The primary constraint to future development in the South Delta-Tuk Peninsula will be lack of natural gas markets at prevailing and forecast prices both in Canada and internationally. Transportation of oil from onshore and near-onshore reserves will depend on the commercial viability of a transportation system which may require supplemental quantities of oil from the Beaufort Sea. Drilling costs in the onshore delta have ranged between \$2-\$3 thousand per metre (1983 dollars). This is approximately twice the cost for drilling farther south in the Mackenzie corridor and is approximately 4-6 times greater than for drilling in Western Canada. In the Beaufort Sea, drilling costs of exploration have ranged between \$10-\$13 thousand per metre (1983 dollars) where artificial islands are used as drilling bases, and \$10 thousand per metre where drillships are used. Market prices for petroleum from the Beaufort Sea-Mackenzie Delta area must be sufficient not only to cover transportation costs but also much higher development costs. Development costs for an oil field such as Tarsiut, located in 22 metres of water, are expected to be in the range of \$4-\$6 billion (1983 \$).

The main environmental concern in the region focuses on the potential impact of oil spills. The extent of damage depends on factors which include the volume of oil spilled, ice conditions, prevailing oceanographic and meteorological conditions, time of year, and success of oil spill countermeasures. Tanker transportation modes potentially pose a greater environmental hazard than pipelines.

TABLE V
DISCOVERED RESOURCES
(best current estimate — recoverable)

DISCOVERY	OIL 10^6m^3	GAS 10^9m^3
Issungnak	15.9	70.8
Niglintgak	3.7	22.7
Parsons	*3.6	62.3
Taglu	*7.2	68.8
Tarsiut	23.8	2.4
Other discoveries (listed by name only)	63.0	60.2
TOTAL	117.2	286.4

*condensate

Other Discoveries

Adgo
Atkinson
Garry North
Garry South
Imnak
Isserk
Itiyok
Ivik N.E.
Ivik S.W.
Kamik
Kenalooak
Kiggavik
Koakoak
Kopanoar
Kugpik
Kumak
Mallik
Mayogiak
Nektoralik
Nerlerk
Netserk
Pelly
Reindeer
West Atkinson
Titalik
Ukalerk
Ya Ya North
Ya Ya South

TABLE VI
OIL AND GAS POTENTIAL

OIL POTENTIAL (10^6m^3)	High Confidence	Average Expectation	Speculative Estimate
South Delta-Tuk Peninsula	8	76	171
Richards Island-Beaufort Sea	287	1271	3060
TOTAL	*307	1347	*2962

GAS POTENTIAL (10^9m^3)	High Confidence	Average Expectation	Speculative Estimate
South Delta-Tuk Peninsula	93	144	402
Richards Island-Beaufort sea	747	1721	4070
TOTAL	*871	1865	*4103

NB Estimates for this region are under review at time of printing
* These numbers do not add arithmetically but must be summed using statistical techniques

SOUTH DELTA-TUK PENINSULA

Area 30 000 square kilometres; includes offshore extension of Tuk fault zone to 71°N.

Geology Proterozoic, Devonian, and Permian clastics, volcanics, and carbonates have been identified in subcrop under the Mesozoic-Cenozoic cover of the South Delta-Tuk Peninsula. Presumably a Cambrian to Silurian succession also underlies the area. Where penetrated the Proterozoic rocks consist of clastics and volcanics; those of the Cambrian to Devonian are carbonates; and the Permian succession consists of clastics. Nine basin-wide Jurassic and Early Cretaceous depositional sequences are recognized. Each generally consists of a thick prograding lens of sandstone and shale of dominantly marine facies. Thickness variations were controlled by a system of basement arches and troughs that were active at the time of deposition. Paleoshorelines mimic the present northeast-southwest orientation although occurring farther southeast onto the craton. Maximum transgression occurred during Albian time. The Jurassic-Lower Cretaceous rocks are unconformably overlain by Upper Cretaceous shales, which are overlain by a thin succession of Tertiary sands.

Drilling History The first exploratory well was drilled in the area in 1962 and oil was first discovered at Atkinson Point in 1970. To date 74 wells have been drilled in the South Delta-Tuk Peninsula region.

Potential Source Rocks The Upper Cretaceous Boundary Creek Formation has been identified as the source rock for the oil at several discoveries. The condensates and gas in the Parsons field are believed to be sourced from shales of the Husky Formation and although it contains abundant terrigenous organic material, its source potential is not yet fully understood. Similarly organic rich shales occur in the Albian Arctic Red Formation.

Potential Reservoir Rocks The interdigitation of shales and sandstones throughout the sequences provide ample opportunity for both reservoir and seal occurrences.

Known Hydrocarbon Occurrences Oil has been discovered at Kugpik, Kamik, Atkinson, West Atkinson, Imnak, and Mayogiak (the Mayogiak and West Atkinson oils are trapped in Devonian carbonates). Major accumulations of natural gas and condensate have been discovered at Parsons Lake where recoverable reserves have been estimated at 62.3 billion cubic metres gas and 3.6 million cubic metres of condensate.

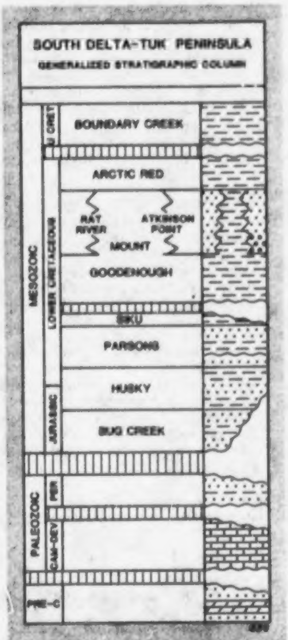

SOUTH DELTA-TUK PENINSULA
GENERALIZED STRATIGRAPHIC COLUMN
MESOZOIC
U CRET
LOWER CRETACEOUS
JURASSIC
PALEOZOIC
PER
CAM-DEV
PRE-C
BOUNDARY CREEK
ARCTIC RED
RAT RIVER
ATKINSON POINT
MOUNT
GOODENOUGH
SIKU
PARSONS
HUSKY
BUG CREEK
GSC

Figure 3.24 Mackenzie Delta-Tuk Peninsula

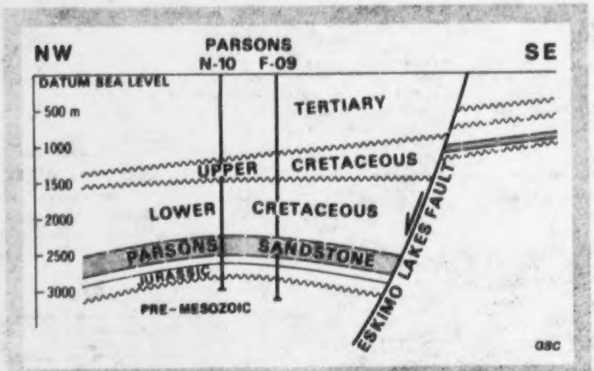

NW
PARSONS
N-10
F-09
SE
DATUM SEA LEVEL
500 m
1000
1500
2000
2500
3000
TERTIARY
UPPER CRETACEOUS
LOWER CRETACEOUS
PARSONS SANDSTONE
JURASSIC
PRE-MESOZOIC
ESKIMO LAKES FAULT
GSC

Figure 3.23 Schematic structure section, Parsons Lake Gas Field (after Cote et al 1973)

RICHARDS ISLAND — BEAUFORT SEA

Area Approximately 55 000 square kilometres extends seaward to the 200 metre isobath.

Geology The basin contains a series of late Mesozoic-Cenozoic depocentres, in which clastic sediments were deposited in a series of migrating deltaic wedges and associated turbidity flow deposits. Rapid basin subsidence and undercompaction of sediments resulted in large scale syndepositional listric faulting and mud diapirism. Nine major depositional sequences deposited in response to eustatic changes in sea level are identified. Each have complex facies distributions reflecting the varied position in time and space of shelf to slope breaks and channel positions of the major sediment influx. In general, each sequence progrades farther basin-ward than its predecessor resulting in downlapping and offlapping relationships.

Drilling History The first exploratory well drilled in the area was on Richards Island in 1966 (Reindeer D-27). Drilling activity moved offshore, with the use of artificial islands beginning in 1973 and ice-strengthened drillships in 1976. To date a total of 82 wells have been drilled in the Richards Island-Beaufort Sea area.

Potential Source Rocks The actual source rocks have yet to be identified. Studies suggest that significant vertical migration has occurred and the peculiar nature of the recovered crudes suggests they were generated from resin-enriched terrestrial organic material at lower than normal levels of thermal maturity.

Potential Reservoir Rocks Reservoir quality sandstones are present throughout the basin.

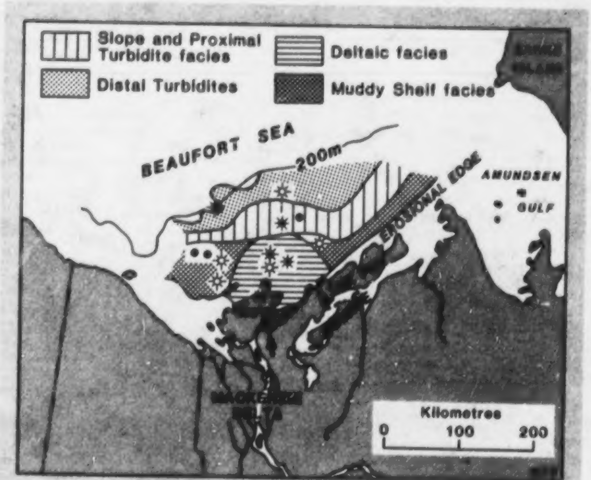

Slope and Proximal Turbidite facies
Deltaic facies
Distal Turbidites
Muddy Shelf facies
BEAUFORT SEA
200m
EROSIONAL EDGE
AMUNDSEN GULF
MACKENZIE DELTA
Kilometres
0
100
200

Figure 3.25 Paleoenvironments of the Kugmallit sequence

Known Hydrocarbon Occurrences To date 26 fields have been discovered in Tertiary reservoirs; five oil, thirteen gas, and eight oil and gas. Major accumulations of gas have been found in the Taglu and Issungnak fields (with estimated recoverable reserves of 68 billion and 71 billion cubic metres of gas respectively). The Tarsiut field is one of the larger oil accumulations discovered to date (with estimated reserves of 23.8 million cubic metres of oil).

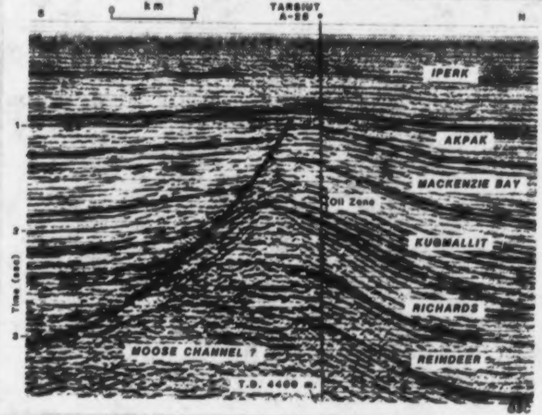

S
0
km
2
TARSIUT A-25
N
1
2
3
Time (sec)
IPERK
AKPAK
MACKENZIE BAY
Oil Zone
KUGMALLIT
RICHARDS
MOOSE CHANNEL ?
REINDEER
T.D. 4400 m.

Figure 3.26 Seismic section through Tarsiut Field

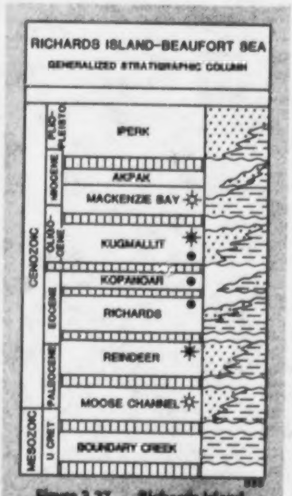

RICHARDS ISLAND–BEAUFORT SEA
GENERALIZED STRATIGRAPHIC COLUMN
CENOZOIC
MESOZOIC
PLIO-PLEISTO
MIOCENE
OLIGO-CENE
EOCENE
PALEOCENE
U CRET
IPERK
AKPAK
MACKENZIE BAY
KUGMALLIT
KOPANOAR
RICHARDS
REINDEER
MOOSE CHANNEL
BOUNDARY CREEK

Figure 3.27 Richards Island-Beaufort Sea

ARCTIC ISLANDS

Introduction

Four major tectono-stratigraphic regions are differentiated making up the geological framework of the Canadian Arctic Islands region. The sediments in the various basins represent all geologic systems between Precambrian and Recent. With the exception of the youngest sediments, which have not been deeply buried, and the oldest sediments which have not been adequately tested, all the depositional successions have yielded indications of hydrocarbons. The four tectono-stratigraphic regions (see Figure 3.29) considered to be potentially petroleum bearing are the Arctic Stable Platform, the Arctic Fold Belt, the Sverdrup Basin, and the Arctic Coastal Plain. Estimates of potential have been made for the first three regions. The Arctic Coastal Plain is known to contain thick (12 000 m) accumulations of sediments of favorable facies, but the geographic remoteness, and the large proportion of the basin that lies beneath the shifting Arctic Ocean icepack has effectively removed the region from possible economic exploitation. Consequently there exists a minimum of geological data on which to base an assessment.

Reserves

Exploration to date has resulted in eighteen discoveries including ten gas, three oil, and five oil and gas fields. Several of these discoveries are large enough to imply economic viability, however, a number are too small to justify a transportation system under anticipated economic conditions. Because

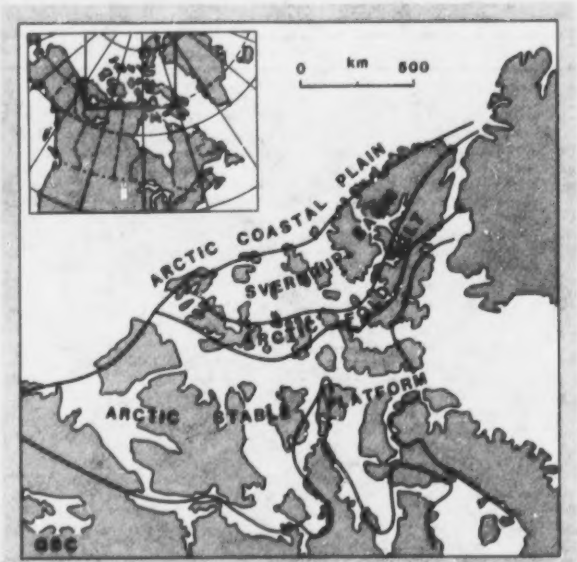

0 km 500
ARCTIC COASTAL PLAIN
SVERDRUP BASIN
ARCTIC FOLD BELT
ARCTIC STABLE PLATFORM
GSC

Figure 3.29 Arctic Islands assessment areas

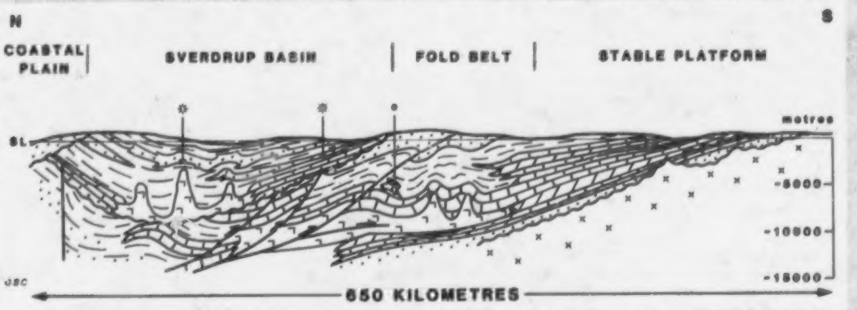

N
S
COASTAL PLAIN
SVERDRUP BASIN
FOLD BELT
STABLE PLATFORM
metres
SL
-5000
-10000
-15000
GSC
650 KILOMETRES

Figure 3.28 Schematic stratigraphic relationships, Arctic Islands

none of the discoveries has been fully delineated, and because of the uncertainty associated with their economics, use of the expression established reserves could be misleading. The values expressed in Table VII are, therefore, labelled "best current estimates" of "discovered resources". The values given reflect quantities that can be considered likely to exist on the basis of existing control plus a subjective opinion of surrounding geology. As such, they represent a necessarily conservative series of estimates that will change as new information is added by delineation drilling and from analysis of pool performance. Discovered resources listed in Table VII do not include natural gas liquids (NGLs), although there are indications that significant quantities of NGLs may be recovered from some gas fields when they are placed on production.

Potential

The Arctic Islands Region is estimated to contain undiscovered potential resources of 686 million cubic metres of oil and 2257 billion cubic metres of gas (average expectation) as shown in Table VIII. Oil potential is estimated to be highest in the Sverdrup basin, in both Mesozoic and late Paleozoic rocks. Recent oil discoveries provide a better understanding of the controls of oil accumulation and added encouragement for its occurrence. Opportunities for future gas discovery also are considered greatest in the Sverdrup basin. To date, most of the diagnostic exploratory wells have tested a limited number of very prolific plays in the Mesozoic part of the basin. Deeper parts of the Mesozoic succession and a number of relatively untested Late Paleozoic plays are estimated to have at least as much potential as those that have been tested.

Throughout the Arctic Islands region, there are many untested plays, most of which would be under intense exploration if they were located in Southern Canada. The remoteness, logistic difficulties and resultant high costs have contributed to a relatively slow pace of exploration in the Arctic frontier. Several hundred more wildcat wells would be required to provide a reliable evaluation of the region's full potential.

Economic and Environmental Considerations

The tendency for the Sverdrup Basin to yield mostly natural gas has been confirmed through the discovery of large quantities of natural gas relative to oil. Choice of development and operating systems in the Arctic is necessarily tentative at this time. Consequently, development and operating costs are uncertain, as are transportation costs, whether by marine tanker or pipeline mode. Costs of producing hydrocarbons, which are likely to be located primarily offshore will be a function of water depths, the harsh climatic conditions, and reservoir characteristics. In the region of land-fast ice, where ice does not move significantly over long periods of time, there are drilling cost advantages relative to the Beaufort Sea because drilling can take place from reinforced ice platforms. In 1983 dollars, cost per metre for offshore exploratory drilling ranges between $4-$5 thousand whereas drilling onshore in the Arctic ranges between $3-$4 thousand per metre. These costs are indicative of the relative high development investment required in the Arctic. By way of comparison, costs in the Arctic Islands offshore could be 10 to 15 times higher than for resources located in western Canada. However, this comment must be qualified in that reserves found per metre drilled have been greater in the Arctic than in western Canada.

As in the Beaufort Sea, producing hydrocarbons from the Arctic Islands is on the technological frontier. In both areas, it may be necessary to use pilot projects to demonstrate that reserves can be produced and delivered to market on a year round basis, or even seasonally, with some degree of reliability.

Environmentally, there is a concern over the impact that major oil spills could have on the aquatic animals. Tanker modes are generally considered to have greater potential impact on the environment than pipelines. There appears to be a greater degree of uncertainty regarding the impact of environmental damage in the Arctic Islands than other frontier regions. This is due to a relatively incomplete understanding of the physical environmental, factors such as bathymetry, soil conditions, permafrost, etc.

TABLE VII
DISCOVERED RESOURCES
(best current estimate — recoverable)

DISCOVERY	OIL 10^6m^3	GAS 10^9m^3
Cisco	48.7	4.4
Drake	—	98.5
Hecla	—	85.5
Jackson Bay	—	22.7
King Christian	—	17.3
Kristoffer	—	27.1
MacLean	3.0	13.6
Thor	—	11.9
Whitefish	—	57.2
Other discoveries (listed by name only)	24.4	22.8
TOTALS	76.1	361.0

Other discoveries
Balaena
Bent Horn
Cape MacMillan
Char
Roche Point
Romulus
Sculpin
Skate
Wallis

TABLE VIII
OIL AND GAS POTENTIAL (RECOVERABLE)

OIL POTENTIAL (10^6m^3)	High Confidence	Average Expectation	Speculative Estimate
Arctic Stable Platform	55	175	348
Arctic Fold Belt	36	85	156
Sverdrup Basin	210	426	1035
TOTALS	*316	686	*1305
GAS POTENTIAL (10^9m^3)	**High Confidence**	**Average Expectation**	**Speculative Estimate**
Arctic Stable Platform	85	239	467
Arctic Fold Belt	90	218	355
Sverdrup Basin	800	1800	3483
TOTALS	*1100	2257	*3662

* These numbers do not add arithmetically but must be summed using statistical techniques

ARCTIC STABLE PLATFORM

Area 780 000 square kilometres; approximately 370 000 square kilometres onshore; 410 000 square kilometres offshore.

Geology A blanket of sedimentary rocks up to 3000 metres in thickness overlies ancient crystalline rocks and represents a long period of quiet deposition in shallow epicontinental seas (Figure 3.31). Subsequent to their deposition, they have remained essentially undeformed. Early clastic sediments transgressed over the largely crystalline basement to be followed by mainly carbonate sediments of the shallow epicontinental seas. Breaks in the sedimentary record resulted from eustatic changes in sea level which also controlled the position of various changes in facies of the carbonate sediments. The rocks range in age from Cambrian to Devonian.

Drilling History The first well to be drilled on the Stable Platform was Panarctic *et al* Garnier 0-21 during the summer of 1971. Since then 19 additional wells have been drilled on the Stable Platform.

Potential Source Rocks No seeps have yet been reported from the area although many geologists have reported bitumen-like residues and or fetid petroliferous odors in freshly broken rocks. Limited organic geochemistry indicates high wet gas and good extract yields locally from shales and associated carbonates of the Silurian Cape Phillips Formation which are the deeper water equivalents of the Allen Bay to Read Bay carbonates.

Potential Reservoir Rocks Basal sandstones are poorly consolidated and usually have good porosity in outcrop. Vuggy porosity occurs in many of the carbonates which also can be enhanced by leaching related to unconformity surfaces. Reef; carbonate banks and associated debris flows also may be the loci of porosity development (Figure 3.30).

Known Hydrocarbon Occurrences There are presently no known reserves of either natural gas or oil on the Stable Platform.

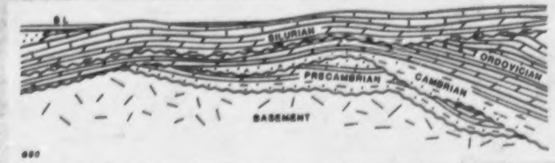

S.L.
SILURIAN
ORDOVICIAN
PRECAMBRIAN
CAMBRIAN
BASEMENT
GSC

Figure 3.30 Stratigraphic trap configurations in platform stratigraphy

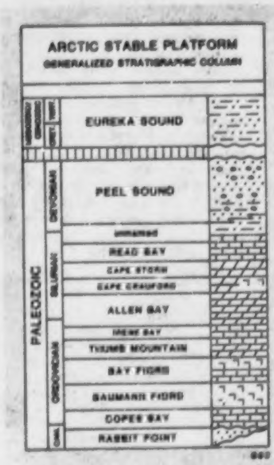

ARCTIC STABLE PLATFORM
GENERALIZED STRATIGRAPHIC COLUMN
EUREKA SOUND
PALEOZOIC
DEVONIAN
PEEL SOUND
SILURIAN
unnamed
READ BAY
CAPE STORM
CAPE CRAUFORD
ALLEN BAY
ORDOVICIAN
IRENE BAY
THUMB MOUNTAIN
BAY FIORD
BAUMANN FIORD
COPES BAY
RABBIT POINT
GSC

Figure 3.31 Arctic Stable Platform

ARCTIC FOLD BELT

Area 240 000 square kilometres; approximately 150 000 square kilometres onshore, 85 000 square kilometres offshore.

Geology The region is underlain by a wedge of Paleozoic carbonate rocks and equivalent shales thickening from a variable hingeline with the widespread rocks of the Stable Platform region into a deeper basin (Figure 3.33). In ways similiar to the Western Canada Sedimentary Basin, there are rapidly changing sedimentary facies with shales interfingering with carbonates near the so-called "hingeline" of the basin. Reef buildups occur between the carbonates of the shelf and the muds of the deeper basin. The youngest sediments represent interlaced clastic wedges derived from early phases of the Late Devonian — Early Carboniferous Ellsmerian Orogeny. The region is one of complex structures combining detachment folds and thrusts produced during compression modified by vertical movement of evaporites in response to both sediment loading and tectonic stress (Figure 3.32).

Drilling History The first well drilled in the Arctic Islands was drilled within the Fold Belt at Winter Harbour Melville Island during 1962. Since then only 32 wells have tested plays in this region.

Potential Source Rocks No seeps have been reported, however bitumen filled vugs are common in early Paleozoic carbonate rocks. Organic rich shales are common within Ordovician, Silurian, and Devonian sequences which could represent moderate to excellent source rocks.

Potential Reservoir Rocks Reservoir rocks exist in the Ordovician platform sequence, in reefal carbonates adjacent to the shale basin, and in the Upper Devonian clastic rocks. Shale intervals above the reservoir rocks should serve as seals for any reservoired hydrocarbons.

Known Hydrocarbon Occurrences In the Bent Horn 'field' on Cameron Island, oil was encountered in reefal carbonates of Devonian age. The Winter Harbour well on Melville Island tested 1.7 thousand cubic metres per day of natural gas from Upper Devonian clastic rocks.

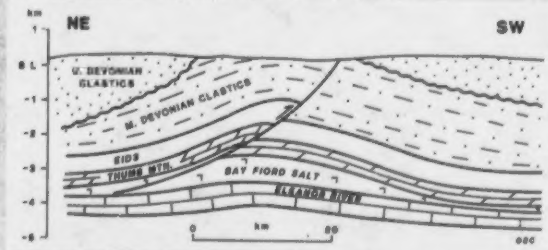

km
1
0 L
-1
-2
-3
-4
-5
NE
SW
U. DEVONIAN CLASTICS
M. DEVONIAN CLASTICS
EIDS
THUMB MTN.
BAY FIORD SALT
ELEANOR RIVER
0
km
80
GSC

Figure 3.32 Structural traps above and below evaporites

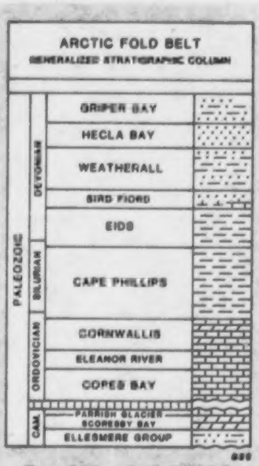

ARCTIC FOLD BELT
GENERALIZED STRATIGRAPHIC COLUMN
PALEOZOIC
DEVONIAN
SILURIAN
ORDOVICIAN
CAM.
GRIPER BAY
HECLA BAY
WEATHERALL
BIRD FIORD
EIDS
CAPE PHILLIPS
CORNWALLIS
ELEANOR RIVER
COPES BAY
PARRISH GLACIER
SCORESBY BAY
ELLESMERE GROUP
GSC

Figure 3.33 Arctic Fold Belt

SVERDRUP BASIN

Area 313 000 square kilometres; approximately 145 000 square kilometres onshore; 168 000 square kilometres offshore.

Geology The greater part of the basin has been filled with approximately 13 000 metres of sediments and minor intrusions of basic sills and dykes. The rocks range from Carboniferous (Visean) to Tertiary in age. Early sediments consisted of carbonate rocks deposited around the margins of the basin with a thick evaporite sequence deposited in the basin centre (Figure 3.28). Later deposition was dominated by the influx of clastic sediments derived from the continental interior and deposited in major deltaic complexes. The complex distribution of clastic facies resulted from the interaction of sediment supply and changes in sea level. The basin was developed on deformed rocks of the Franklinian geosyncline and were themselves deformed during the Early Tertiary Eurekan Orogeny.

Drilling History (to 1983) One hundred and fourteen wells (88 exploratory) have been drilled, twenty-eight of which were drilled offshore.

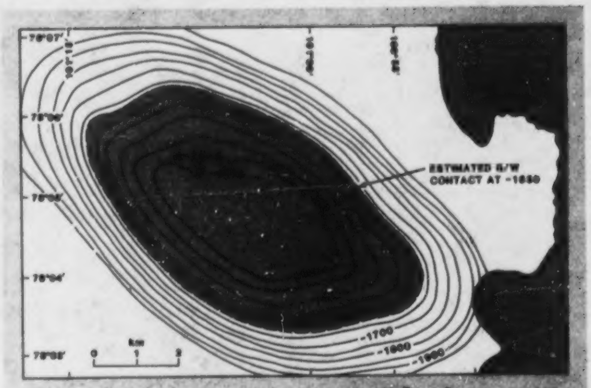


Figure 3.34 Structure contour map on Heiberg Group Jackson Bay Field. Contours in metres

Potential Source Rocks The source rocks for the hydrocarbons found to date, have been identified as the organic rich shales within the Late Triassic Hoyle Bay Formation. Maturation studies indicate that the thermally mature zone for this source rock, mimics the shape of the basin with locally developed overmature areas overprinted on the regional distribution.

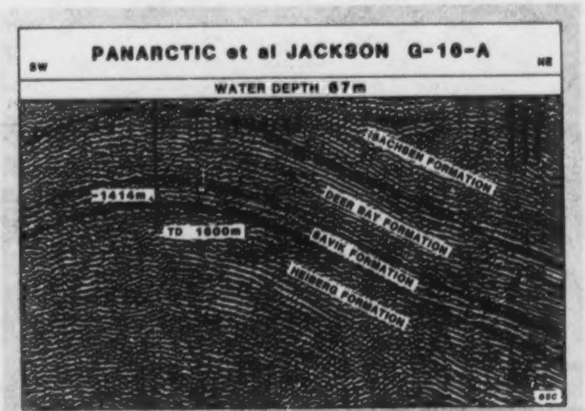


Figure 3.35 Seismic section through Jackson Bay Field

Potential Reservoir Rocks Reservoir quality sandstones are developed within the Isachsen, Awingak, Heiberg, Schei Point, and Bjorne stratigraphic units of Mesozoic age; and in both Carboniferous and Permian sequences. Potential carbonate reservoirs are inferred from outcrop sections to occur in the late Paleozoic successions.

Known Hydrocarbon Occurrences Seventeen discoveries or significant shows have been found to date that indicate a reserve at a best current estimate of 76 million cubic metres of recoverable oil and 361 billion cubic metres of marketable natural gas.

Pool Size Three of the natural gas discoveries are estimated to fall into the 50-100 billion cubic metres size range; the largest oil pool is currently estimated to contain approximately 50 million cubic metres. None of the accumulations can be considered fully delineated.

EASTERN CANADA OFFSHORE

Introduction

Sedimentary basins on the continental margin of eastern Canada trend northeast from Georges Bank to the Grand Banks then north-northwest to Baffin Bay a total distance of about 5500 km. There are five main depocentres along this trend. The Scotian Basin which reaches from eastern Georges Bank to the western Grand Banks, the East Newfoundland Basin which contains the giant Hibernia oil and gas field, the Hopedale and Saglek Basins on the Labrador margin and Baffin Bay, Figure 3.36. These basins are flanked and separated by a series of positive elements which include the Yarmouth Arch, the Avalon Uplift, the Cartwright Arch and Davis Strait High.

Although the basins are progressively younger northward, each formed through passive margin tectonics and subsidence with subsequent outbuilding of clastic wedges. All of the offshore regions with thicknesses more than one kilometre are considered to have potential for oil and gas occurrence. Although some Paleozoic rocks are present on the margin, the major hydrocarbon potential is within the thick Mesozoic and Cenozoic sequences which predominate. More specifically the most significant occurrences to date have been in the Upper Jurassic-Lower Cretaceous clastic sequences with adjacent shales providing the oil and gas source.

Reserves

Exploration to date has identified several large gas and oil discoveries, plus numerous presently non-economic accumulations. Because none of the discoveries has been fully delineated, plus the economic uncertainties associated with their development, the volumes of gas and oil shown in Table IX are considered as best current estimates of discovered resources rather than the more conventional term of established reserves. Values shown are necessarily conservative but are considered technically recoverable, without consideration of economic constraints.

The tabulation of discovered resources includes several recent discoveries. For the fields listed, the values reflect quantities currently thought to be demonstrated with reasonable confidence; as additional delineation drilling occurs, some of the fields could well turn out to be two or three times larger than currently shown.

Potential

The assessed portion of the East Coast basins include Georges Bank, the Scotian Shelf, Grand Banks South, East Newfoundland Shelf, Labrador and Southern Baffin Island shelves,

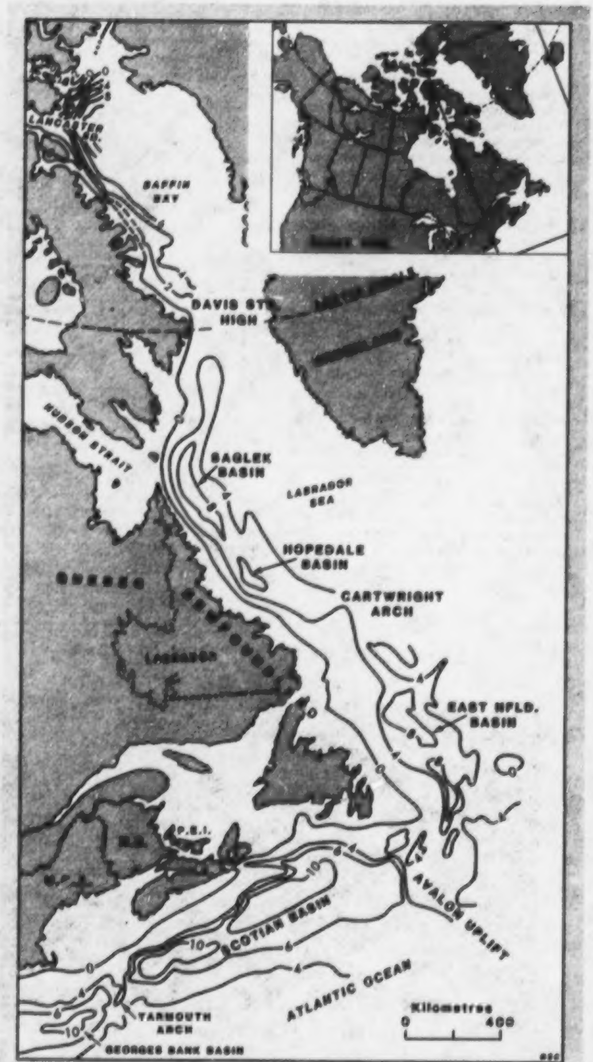


Figure 3.36 Index map of offshore basins showing total *Mesozoic-Cenozoic* sediment fill in kilometres (after Purcell *et al* 1980)

plus the East Newfoundland Basin, Baffin Bay and Lancaster Sound. These areas are estimated to contain more than 2400 billion cubic metres of gas and almost 1900 million cubic metres of oil (average expectation) as shown in Table X. Oil potential is considered greatest in the East Newfoundland Shelf and Basin areas with much lower prospects to the north and south. Gas potential is estimated to be greatest in the Labrador Shelf and Scotian Shelf areas. Exploratory drilling to date has been concentrated in three basins, on plays currently viewed as most prospective. Many more plays have yet to be tested, and whole basins such as Baffin Bay and East Newfoundland Basin are virtually untouched. There are numerous opportunities for major and giant size fields yet to be discovered. Shelf area estimates given in Table X include the uppermost or currently accessible parts of the continental slope.

TABLE IX
DISCOVERED RESOURCES
(best current estimate — recoverable)

DISCOVERY	OIL 10^6m^3	GAS 10^9m^3
SCOTIAN SHELF		
Thebaud	*2.2	12.2
Venture	*6.4	56.6
Others discoveries (listed)	5.6	42.9
EAST NEWFOUNDLAND		
Hibernia	159.0	56.6
4 other discoveries (listed)	47.8	—
LABRADOR SHELF		
Bjarni, North Bjarni	*2.5	43.2
Gudrid	*0.5	13.7
Hekja	—	11.8
2 other discoveries (listed)	1.1	8.6
TOTAL East Coast Offshore	225.1	245.6

Other discoveries

SCOTIAN SHELF
- Arcadia
- Banquereau
- Citnalta
- Cohasset
- Intrepid
- Olympia
- Onondaga
- Primrose
- Sable Island
- South Venture

EAST NEWFOUNDLAND
- Ben Nevis
- Hebron
- Nautilus
- South Tempest

LABRADOR SHELF
- Hopedale
- Snorri

*condensate

Economic and Environmental Considerations

Scotian Shelf For the quantities of natural gas that have been discovered in the Sable Island area, studies show that particularly costly circumstances exist. This is due to the location offshore in 20 to 30 metres of water and the composition of the gas. The gas stream will require initial treatment at offshore facilities before being transported by subsea pipeline to a mainland processing plant. Alternatively, liquefied natural gas and gas liquids could be transported by a marine tanker shuttle system.

Exploratory drilling costs in this area are in the range of $2-$5 thousand per metre ($1983). Development of the Venture gas field, based on pipelining to the mainland, has been estimated to cost $2.5-$3.0 billion to allow recovery of 60-90 billion cubic metres of natural gas. A major constraint facing development in this area is the future marketability of natural gas both in Canada and internationally.

Hibernia Discoveries of oil and associated gas have raised the possibility of commercial production from this area by the end of this decade. Studies have been made on possible development, production and transportation systems. Nevertheless, plans are tentative and costs are expected to be high. Cost will be a function of the design required to cope with severe sea, ice and weather conditions, as well as design to allow mobility of development and production platforms. Exploration drilling costs are in the range of $8-$15 thousand per metre. For transportation, the tanker mode is preferred, as pipelining appears impractical due to the physical conditions on the ocean floor. Estimates suggest that development costs for Hibernia will be in the range of $5-$7 billion for a recoverable oil reserve estimated to be between 200 and 400 million cubic metres. In terms of marketability, Hibernia is favourably located in relation to consuming regions, which will serve to minimize transportation costs.

The major environmental risk is an offshore oil spill, whether a consequence of a subsea blowout, damage to subsea production systems or pipelines due to icebergs or tanker collision.

TABLE X
OIL AND GAS POTENTIAL (RECOVERABLE)

OIL POTENTIAL (10^6m^3)	High Confidence	Average Expectation	Speculative Estimate
Georges Bank	10	168	350
Scotian Shelf**	8	72	139
Grand Banks (South)	2	50	95
East Newfoundland Shelf	300	1128	2190
East Newfoundland Basin	130	270	720
Labrador Shelf	10	134	275
Baffin Bay - Lancaster Sound	5	55	158
TOTAL	*512	1877	*3392

GAS POTENTIAL (10^9m^3)	High Confidence	Average Expectation	Speculative Estimate
Georges Bank	37	150	307
Scotian Shelf**	111	508	991
Grand Banks (South)	20	90	180
East Newfoundland Shelf	170	290	530
East Newfoundland Basin	110	370	900
Labrador Shelf	160	745	1627
Baffin Bay - Lancaster Sound	18	270	803
TOTAL	*725	2423	*4713

* These numbers do not add arithmetically but must be summed using statistical techniques

** Estimates for this area are under review at time of printing

GEORGES BANK

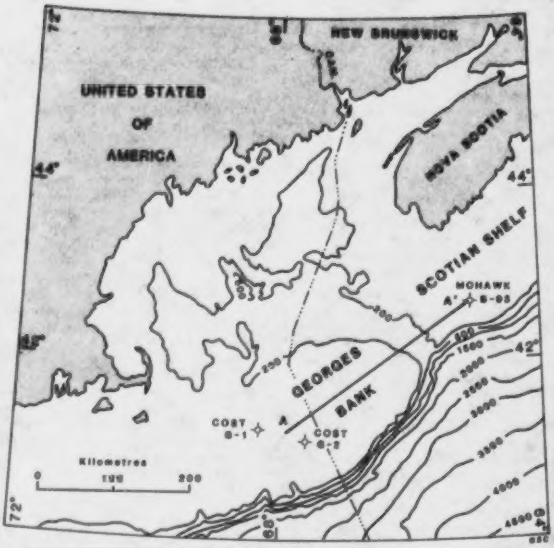


Figure 3.37 Index map of Georges Bank area. Bathymetry in metres

Area Approximately 27 500 square kilometres of Georges Bank, a physiographic feature, lies east of the equidistance line between Canada and the U.S. All of this area is offshore.

Geology Georges Bank Basin underlies the western part of Georges Bank and the southwestern end of the Scotian Basin underlies the eastern part. Between the two lies the Yarmouth Arch, Figure 3.38. Georges Bank Basin is a structural sag approximately 200 x 90 kilometres whose axis trends northeast and plunges southwesterly. The basin formed in the Early Jurassic over a folded and faulted basement complex inset with down-faulted remnants of probable Triassic sediments and volcanics. The basin had its most rapid period of subsidence during the Early and Middle Jurassic when up to four kilometres of predominately carbonate rocks were deposited in a warm shallow epicontinental sea. The carbonates were flanked shoreward by fine and coarse clastics. An additional four kilometres of paralic facies with some shelf edge carbonates were deposited during the balance of the Jurassic and in the Cretaceous and Tertiary Periods.

The Scotian Basin underlies the easternmost 50 kilometres of Georges Bank and contains up to 10 kilometres of sediment fill, nearly half of which may consist of Triassic and Lower Jurassic rift valley clastics, salt and sabkha deposits. These are overlain by thick wedges of Middle Jurassic through Tertiary clastics. A continuation of the Upper Jurassic shelf edge carbonates rims the northwest flank of the Basin.

Drilling History No wells have been drilled in the Canadian part of Georges Bank.

Potential Source Rocks One well on the western Scotian Shelf and two U.S. wells in Georges Bank Basin provide stratigraphic and geochemical control.

The organically richest rocks occur in the Cretaceous and Upper Jurassic. Older, deeper rocks which are thermally mature, contain dominantly terrestrial organic matter that is likely to be gas prone. Maturation studies from the nearest Scotian Shelf well indicates probable immaturity to depths of 2100 metres in the Middle Jurassic. Because of the rapid deposition and the interfingering of marine and paralic sequences, an average balance of oil and gas source rocks is expected in the Georges Bank area.

Potential Reservoir Rocks The thick Cretaceous and Jurassic sandstones are expected to have good reservoir characteristics. The carbonates will probably be tight unless subjected to leaching and dolomitization. Limited reefoid zones also may occur.

Known and Potential Hydrocarbon Occurrences There are no reserves of either oil or gas on the Canadian part of Georges Bank. Plays within Georges Bank Basin and the Yarmouth Arch are limited to basement related structures. Within the Scotian Basin salt tectonics have created a variety of plays associated with salt diapirs, pillows, growth faults, and stratigraphic traps along the basin flank.

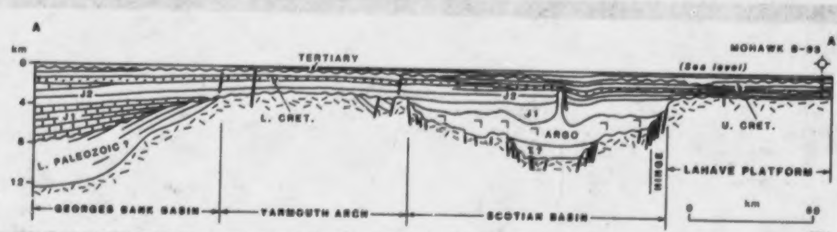


Figure 3.38 Georges Bank structure section (A-A') from Scotian Basin to Georges Bank Basin

SCOTIAN SHELF

Area Approximately 130 000 square kilometres from the centre of Northeast Channel to the centre of Laurentian Channel and from the fall line to the 1500 metre isobath, all offshore.

Geology The main depocentre of the Scotian Basin underlies the eastern part of the Scotian Shelf. It consists of a seaward thickening wedge of Mesozoic and Cenozoic sediments which reaches a maximum thickness of 12 kilometres in the vicinity of Sable Island, Figure 3.36. The oldest sediments are Triassic and lower Jurassic red clastics, evaporites and sabkha rift basin deposits formed during the early stages of the breakup of the North American and African continental plates. These are overlain by thick Middle Jurassic to Lower Cretaceous regressive deltaic sequences and shelf carbonates. The upper Cretaceous and Paleogene are marine transgressive units which are succeeded by regressive Neogene clastics, Figure 3.42. The LaHave Platform which forms the northwest flank of the basin has been a relatively stable element accumulating up to four kilometres of low energy clastics and extensive shelf carbonates.

Drilling History The first deep exploratory well was drilled on Sable Island in 1967. It encountered traces of gas and oil at a total depth of 4,604.3 metres. To June, 1983, 79 wells have been drilled on the shelf testing a total of 53 structures.

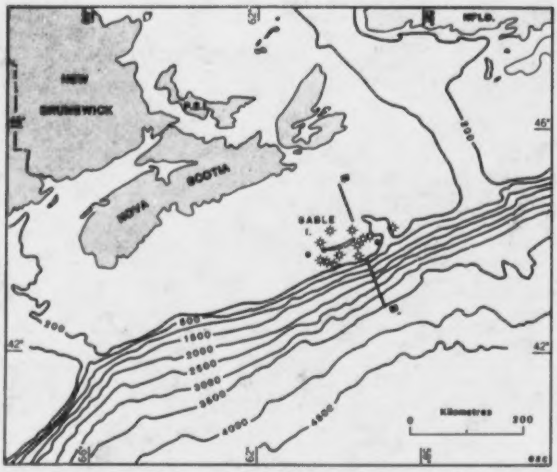

NEW BRUNSWICK
P.E.I.
NOVA SCOTIA
NFLD.
SABLE I.
B
B'
200
500
1500
2000
2500
3000
3500
4000
4500
46°
42°
Kilometres
0
200
GSC

Figure 3.39 Index map of Scotian Shelf showing some of oil and gas discoveries around Sable Island. Bathymetry in metres

Potential Source Rocks Extensive geochemical analyses of material from exploratory drilling indicate that, coincident with the depocentre of the Scotian Basin, lowermost Cretaceous and older sediments are thermally mature. In this area, the Verrill Canyon Formation shale, containing Type III organic matter is largely gas prone and has been the source for hydrocarbons trapped in Upper Jurassic and Lower Cretaceous reservoirs, as at Venture and West Sable Island. The pre-Upper Jurassic source rocks, overmature in the basin, may be within the peak generating range on the flanks of the basin. Upper Cretaceous and Tertiary source rocks, with a higher content of Type I and II organic matter are thermally immature.

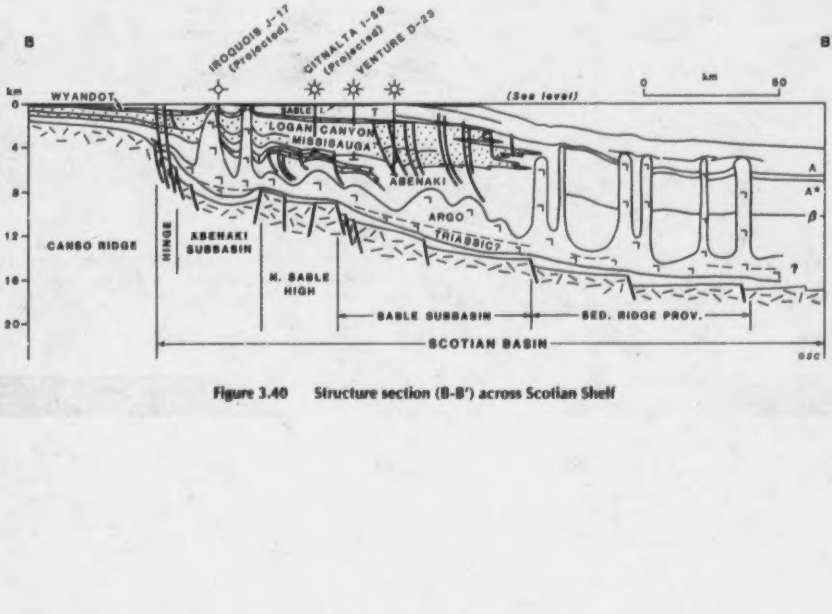

B
B'
IROQUOIS J-17 (Projected)
CITNALTA I-59 (Projected)
VENTURE D-23
km
0
4
8
12
16
20
WYANDOT
(Sea level)
0
km
50
SABLE I.
T
LOGAN CANYON
MISSISAUGA
ABENAKI
ARGO
TRIASSIC?
A
A*
β
?
CANSO RIDGE
HINGE
ABENAKI SUBBASIN
N. SABLE HIGH
SABLE SUBBASIN
SED. RIDGE PROV.
SCOTIAN BASIN
GSC

Figure 3.40 Structure section (B-B') across Scotian Shelf

Potential Reservoir Rocks The thick fluvial and deltaic sandstones in the Scotian Basin generally have good porosity and provide excellent reservoirs. The sandstones on the LaHave Platform are generally fine grained and thinner. Ample shale interbeds are available for reservoir seal. The thick shelf carbonates (Abenaki Formation) are generally tight although occasional occurrences of secondary porosity have been noted in wells drilled to date.

Known and Potential Hydrocarbon Occurrences Salt mobilization since the Middle Jurassic has resulted in numerous diapirs and pillows as well as an extensive complex of down-to-basin faults. Such structures have provided the trapping mechanism for twelve significant gas and oil discoveries and seven additional wells with oil and gas shows. The largest accumulation is at Venture where an estimated 57 billion cubic metres of gas has been delineated. Other plays on the Scotian Shelf include basement structures, the carbonate front and stratigraphic traps.

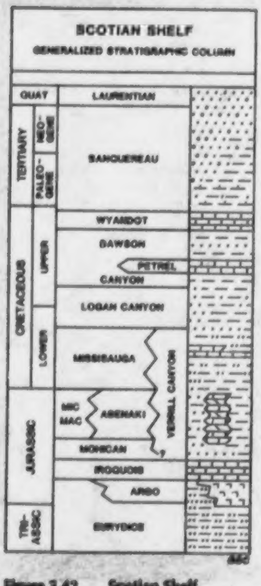

SCOTIAN SHELF
GENERALIZED STRATIGRAPHIC COLUMN
QUAT
LAURENTIAN
TERTIARY
NEO-GENE
PALEO-GENE
BANQUEREAU
CRETACEOUS
UPPER
WYANDOT
DAWSON
PETREL
CANYON
LOGAN CANYON
LOWER
MISSISAUGA
VERRILL CANYON
JURASSIC
MIC MAC
ABENAKI
MOHICAN
?
IROQUOIS
ARGO
TRI-ASSIC
EURYDICE
GSC

Figure 3.42 Scotian Shelf

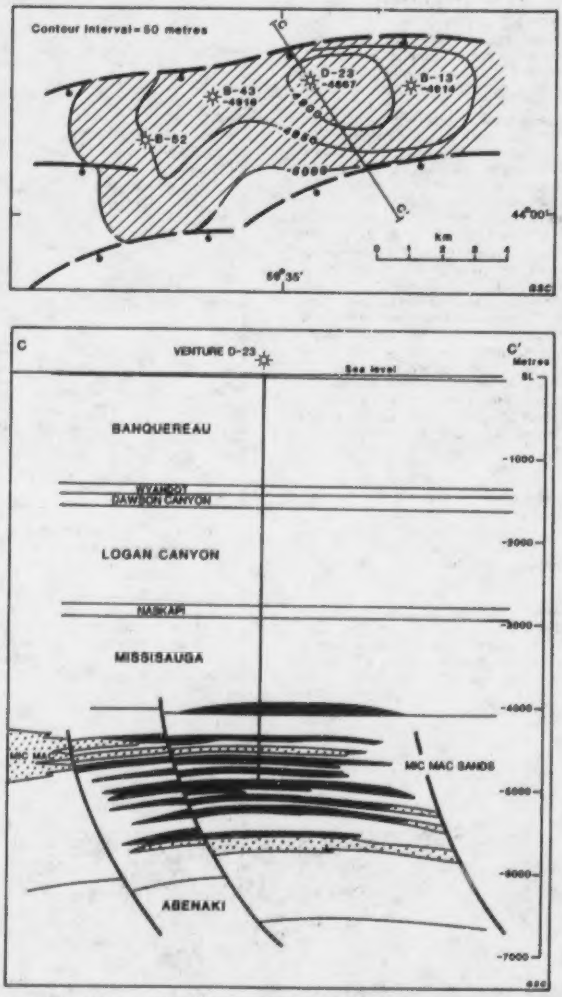

Contour interval = 50 metres
C
D-23
-4867
B-13
-4914
B-43
-4916
B-52
-4900
-4950
-5000
C'
44°00'
km
0
1
2
3
4
59°35'
GSC
C
VENTURE D-23
C'
Metres
Sea level
SL
BANQUEREAU
-1000
WYANDOT
DAWSON CANYON
-2000
LOGAN CANYON
NASKAPI
-3000
MISSISAUGA
-4000
MIC MAC
MIC MAC SANDS
-5000
-6000
ABENAKI
-7000
GSC

Figure 3.41 Map of Venture Field. Generalized structure section Venture Gas Field. Gas pay shaded solid

GRAND BANKS (SOUTH)

Area Approximately 170 000 square kilometres all offshore.

Geology Thick rift basin and marine deposits occur in structural subbasins, preserved as remnants within the Avalon Uplift, beneath the regional mid-Cretaceous unconformity. This setting developed during the separation of the North American and European continental plates. Basins recognized include Whale, Horseshoe and Carson within the Avalon Uplift and South Whale and Flemish Basins flanking the Uplift, Figure 3.43. Upper Paleozoic and Triassic through Upper Jurassic sediments in these subbasins are moderately deformed and have undergone extensive erosion, Figure 3.44. A thin basal transgressive sand overlies the unconformity and is succeeded by up to two kilometres of Upper Cretaceous and Tertiary shales and mudstones. In the southern half of the area, these units overlie basement. The eastern extremity of the Scotian Basin, the South Whale Subbasin, lies to the west of the Avalon Uplift and contains thick Lower Cretaceous, Jurassic and older successions.

Drilling History The first two exploratory wells Tors Cove and Grand Falls were drilled in 1966. Between 1971 and 1975, 28 additional wells were drilled. No wells have been drilled in this area since 1975.

Potential Source Rocks Upper Cretaceous and Tertiary shales overlying the unconformity have potential as source rocks but are thermally immature. Within the subbasins the Lower and Middle Jurassic are considered as poor, gas prone source rocks. The Verrill Canyon shale is expected to provide a mature source rock on the west flank of the Avalon Uplift.

Potential Reservoir Rocks The basal transgressive sand, although porous, has no effective up-dip seal. Clastic wedges on the west flank of the uplift are expected to contain porous sands. Some porosity occurs in thin Upper Cretaceous limestone units.

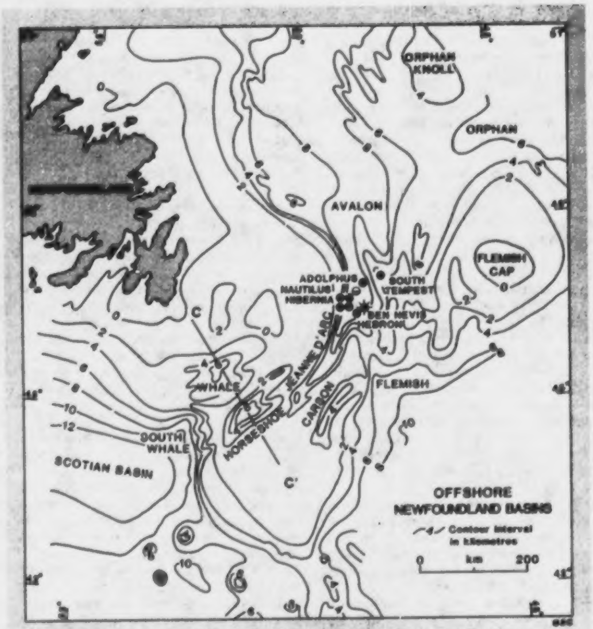

ORPHAN KNOLL
ORPHAN
AVALON
FLEMISH CAP
ADOLPHUS
NAUTILUS
HIBERNIA
SOUTH TEMPEST
BEN NEVIS
HEBRON
JEANNE D'ARC
WHALE
HORSESHOE
CARSON
FLEMISH
SOUTH WHALE
SCOTIAN BASIN
C
C'
0
2
4
6
8
10
12
OFFSHORE NEWFOUNDLAND BASINS
4 Contour interval in kilometres
0 km 200
GSC

Figure 3.43 Index map for basins in Grand Banks (south), East Newfoundland Shelf and East Newfoundland Basin. Contours indicate depth to basement from sea floor (after McMillan 1982)

Known and Potential Hydrocarbon Occurrences Heavy gravity oil was recovered in Heron H-73, drilled on the flank of a salt diapir in the South Whale Subbasin. Salt structures, together with plays at the unconformity constitute the main opportunities for hydrocarbon entrapment.

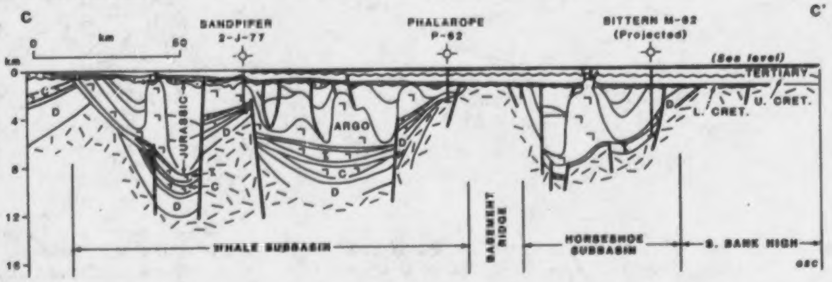

C
C'
0 km 60
km
0
4
8
12
16
SANDPIPER 2-J-77
PHALAROPE P-62
BITTERN M-62 (Projected)
(Sea level)
TERTIARY
U. CRET.
L. CRET.
JURASSIC
ARGO
C
D
BASEMENT RIDGE
WHALE SUBBASIN
HORSESHOE SUBBASIN
S. BANK HIGH
GSC

Figure 3.44 Structure section (C-C') through the Whale and Horseshoe subbasins

EAST NEWFOUNDLAND SHELF

Area Approximately 230 000 square kilometres from the inner limit of sediments to the 400 metre isobath between Grand Banks South and the Cartwright Arch (46°-54°N). All offshore.

Geology This area consists of three partly overlapping depocentres and contains a maximum of more than 14 kilometres of sediments. Oldest beds are a fault bounded Carboniferous succession with thick continental clastics and minor carbonate and evaporite units. The Mesozoic basin formed during the breakup of North America and Europe. It is bounded to the west by a major basement hinge zone and to the east by an outer ridge complex, Figure 3.43. Rift basin Triassic and Jurassic sediments are coarse red clastics and evaporites overlain by marine Jurassic facies. The Lower Cretaceous syndrift sequences include coarse clastics shed north and east into the Avalon Basin. These are covered by transgressive Upper Cretaceous and Tertiary shales with minor sandstone and limestone beds. The Tertiary age depocentre overlaps the other two. It contains up to 5500 metres of predominately mudstones and siltstones.A generalized stratigraphic column is presented in Figure 3.45.

Drilling History The first well in this area was drilled at the extreme southern end of the Jeanne d'Arc subbasin in 1971. Ten additional wells were drilled through 1975 with the only significant show at Adolphus. There was no further drilling until 1979 when the discovery well at Hibernia was drilled. This was closely followed by 15 wells including 6 stepouts at Hibernia. Four of the 9 new wildcats were significant oil discoveries.

Potential Source Rocks An excellent source rock for oil generation has been identified in the Jurassic Kimmeridgian age sequences. All of the oils discovered at Hibernia, Ben Nevis and the Adolphus oil show have been tentatively correlated to this source. These oils indicate a higher level of maturation than has so far been encountered in the source rocks indicating migration from deeper in the basin. Older Jurassic rocks are low in organic carbon content while overlying Cretaceous and Tertiary sediments are terrestrially domained and largely immature.

Potential Reservoir Rocks Basal clastics and carbonates in the upper Paleozoic and lower part of the Mesozoic may provide some reservoirs in areas where they are shallow enough to be drilled. Upper Jurassic and Lower Cretaceous synorogenic clastic rocks have demonstrated good porosity in wells drilled on the west and east flanks of the Avalon Basin but they occur above the oil maturation window. The transgressive Upper Cretaceous and Tertiary section contains reservoir beds, but they occur above the oil maturation window.

Known and Potential Hydrocarbon Occurrences The giant Hibernia oil and gas field lies adjacent to the hinge zone on the flank of the Avalon Basin, Figure 3.47. Best estimate for reserves of gas and oil are 57 billion cubic metres and 159 million cubic metres respectively. The structure is a large rollover anticline associated with the hinge zone, Figure 3.46. Other plays include basement and salt related structures, a complex zone of faulting associated with a south-east trending hinge zone across the Avalon Basin and stratigraphic traps both at the mid Cretaceous unconformity and on the basin flanks. Four wells, Ben Nevis, Nautilus, South Tempest, and Hebron have encountered substantial oil accumulations in these plays.

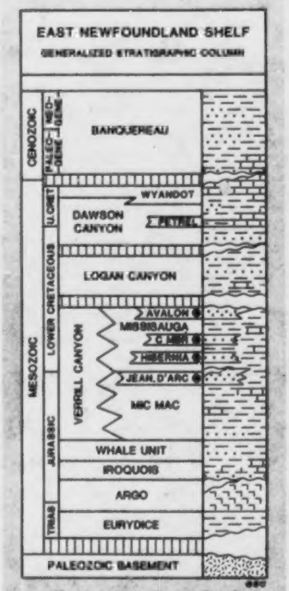

EAST NEWFOUNDLAND SHELF
GENERALIZED STRATIGRAPHIC COLUMN
CENOZOIC
PALEO-GENE
NEO-GENE
BANQUEREAU
MESOZOIC
U. CRET
LOWER CRETACEOUS
JURASSIC
TRIAS
WYANDOT
DAWSON CANYON
PETREL
LOGAN CANYON
AVALON
MISSISAUGA
C MBR
HIBERNIA
JEAN D'ARC
VERRILL CANYON
MIC MAC
WHALE UNIT
IROQUOIS
ARGO
EURYDICE
PALEOZOIC BASEMENT
GSC

Figure 3.45 Generalized stratigraphic column for East Newfoundland Shelf.

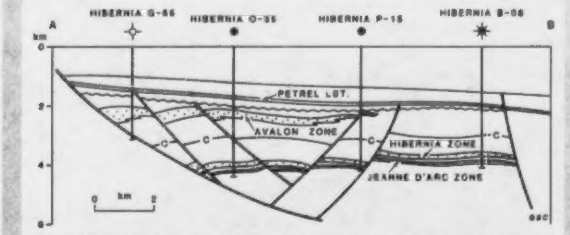

HIBERNIA G-55
HIBERNIA O-35
HIBERNIA P-15
HIBERNIA B-08
A
B
km
0
2
4
6
PETREL LST.
AVALON ZONE
C
C
C
C
HIBERNIA ZONE
JEANNE D'ARC ZONE
0
km
2
GSC

Figure 3.46 Structural cross-section across Hibernia Oil Field showing main oil bearing zones. Line of section indicated on Figure 3.47 (after Benteau and Sheppard 1982)

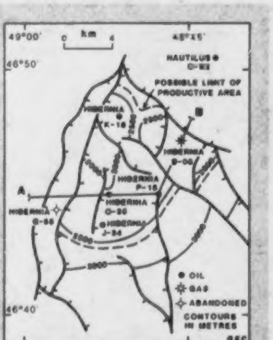

49°00'
48°45'
46°50'
46°40'
0
km
4
NAUTILUS C-92
POSSIBLE LIMIT OF PRODUCTIVE AREA
B
A
HIBERNIA K-18
HIBERNIA B-08
HIBERNIA P-15
HIBERNIA O-35
HIBERNIA J-34
HIBERNIA G-55
2000
3000
OIL
GAS
ABANDONED
CONTOURS IN METRES
GSC

Figure 3.47 Map of Hibernia Oilfield (after Benteau and Sheppard 1982)

EAST NEWFOUNDLAND BASIN

Area Approximately 130 000 square kilometres from the 400 metre isobath to the limit of the continental realm at Orphan Knoll and Flemish Cap to Cartwright Arch. All deep water.

Geology This area (Figure 3.43) is closely related to the adjacent shelf in that it contains the distal parts of all three depocentres, Figure 3.48. The upper Paleozoic sediments are strongly block faulted and overlain by Lower Cretaceous-Jurassic sediments that were deformed and locally eroded at the time of continental breakup. They are unconformably overlain by the Upper Cretaceous and Cenozoic deep water sediments. Based on the results of one well, five regional unconformity bounded sequences are recognized in this area, Figure 3.49. The Paleozoic and Lower Cretaceous beds are shallow marine whereas overlying sequences through late Tertiary are all deep water deposits.

Drilling History Only one well, Texaco *et al* Blue H-28 has been drilled in this area. It was drilled in 1979 in 1,486 m of water to a total depth of 6,088 m below sea level.

Potential Source Rocks Geochemical analyses suggest mature oil source rocks occur in the Cretaceous sediments. The overlying Cenozoic beds are marginally mature. The underlying Paleozoic section is strongly overmature indicative of earlier burial and subsequent erosion. The thick additional Mesozoic section indicated from seismic data to occur off structure should be fully mature. Lower Cretaceous and Jurassic sediments probably occur in this basin, however, organic matter type is unknown.

Potential Reservoir Rocks Porous sandstone reservoir beds were encountered in the Cretaceous but they were water bearing. Only limited porosity occurs in the Paleozoic sandstones. Undrilled Cretaceous and Jurassic strata can be expected to contain reservoir quality beds.

Known and Potential Hydrocarbon Occurrences There are no known hydrocarbon occurrences in this area, however, there are a number of undrilled basement related structures capped by thick Tertiary shales. A number of stratigraphic trapping possibilities occur on the flanks of these structures and at the mid- and Upper Cretaceous unconformities.

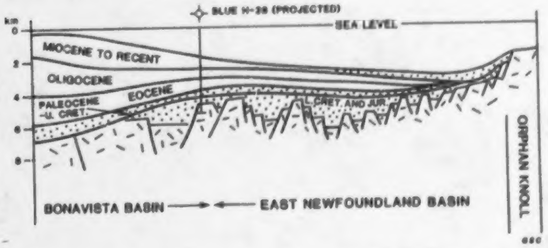

BLUE H-28 (PROJECTED)
SEA LEVEL
km
0
2
4
6
8
MIOCENE TO RECENT
OLIGOCENE
EOCENE
PALEOCENE -U. CRET.
L. CRET. AND JUR.
ORPHAN KNOLL
BONAVISTA BASIN
EAST NEWFOUNDLAND BASIN

Figure 3.48 **Schematic E-W cross-section across East Newfoundland Basin (see Figure 3.43 for location of Orphan Knoll)**

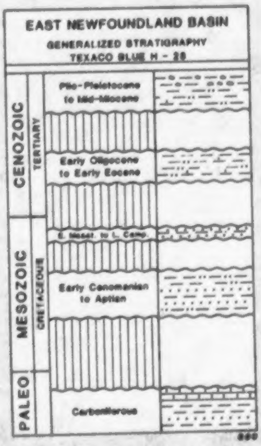

EAST NEWFOUNDLAND BASIN
GENERALIZED STRATIGRAPHY
TEXACO BLUE H - 28
CENOZOIC
TERTIARY
MESOZOIC
CRETACEOUS
PALEO
Plio-Pleistocene to Mid-Miocene
Early Oligocene to Early Eocene
E. Maast. to L. Camp.
Early Cenomanian to Aptian
Carboniferous

Figure 3.49 **Lithology and age of sediments in Texaco *et al* Blue H-28**

LABRADOR SHELF

Area Approximately 180 000 square kilometres from the Cartwright Arch to Davis Strait High, and between the western edge of sediments and the 400 metre isobath, all offshore.

Geology Two depocentres, the Hopedale and Saglek Basins underlie the Labrador Shelf. In the Hopedale Basin, a seaward thickening wedge of Tertiary silty and sandy mudstones overlies an inner shelf graben in which syntectonic Lower Cretaceous volcanics and arkosic sandstones and Upper Cretaceous and lower Tertiary shales were deposited over a block-faulted Paleozoic and Precambrian basement complex. Within the basement complex, there are outliers of Paleozoic carbonates and clastics that provide reservoir rocks. Locally it is possible that the Cretaceous volcanics geophysically mask older Mesozoic sediments as well as the Paleozoic sequences. The Saglek Basin off the Hudson Channel was a Tertiary depocentre and contains up to 10 kilometres of sediments.

Drilling History The first well, Tenneco *et al* Leif E-38, was spudded in 1971 and completed two years later. Since that time drilling has continued slowly (due to a short period each year when ice and weather conditions permit drilling operations) to the present total of 23 wells drilled and three in progress.

Potential Source Rocks Gas and condensates have been discovered in five wells in the Hopedale Basin. Geochemical analyses indicate the condensates are broadly related, and the product of a Type III (terrestrial) kerogen. However, the level of thermal maturation in the wells is generally low suggesting migration of the hydrocarbons from deeper in the basin.

Potential Reservoir Rocks In the Hopedale Basin, the Lower Cretaceous Bjarni sandstone and the Freydis, Gudrid and Leif sand members in the overlying regional shale formations, Figure 3.51, are all of reservoir quality. Locally, reservoir also occurs in the Paleozoic carbonates underlying the coastal plain sequences as at the Gudrid and the Hopedale discoveries. Fluvial and marine sandstone units of Cretaceous and early Tertiary age are expected to provide the main reservoirs in the Saglek Basin.

Known and Potential Hydrocarbon Occurrences There are five gas and condensate discoveries and one oil show in the Hopedale Basin. All are related to basement highs which is the major play in this basin, Figure 3.52. However, stratigraphic traps also may occur in conjunction with the depositional limits of the reservoir units. On the north flank of the Saglek Basin, Aquitaine *et al* Hekja discovered gas in a folded Paleocene sandstone reservoir. This well, with approximately 40 metres of net pay, is the most northerly discovered accumulation of hydrocarbons on the Atlantic margin.

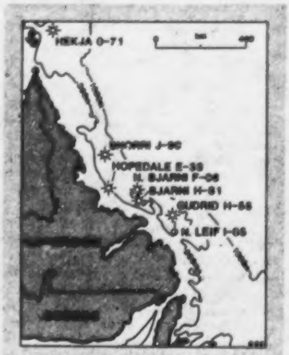

HEKJA O-71
SNORRI J-90
HOPEDALE E-33
N. BJARNI F-06
BJARNI H-81
GUDRID H-55
N. LEIF I-05

Figure 3.50 Location map Labrador Shelf

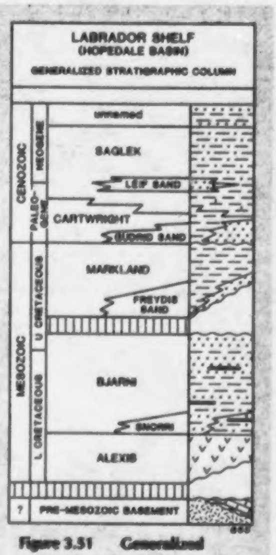

LABRADOR SHELF
(HOPEDALE BASIN)
GENERALIZED STRATIGRAPHIC COLUMN
CENOZOIC
MESOZOIC
NEOGENE
PALEOGENE
U CRETACEOUS
L CRETACEOUS
unnamed
SAGLEK
LEIF SAND
CARTWRIGHT
GUDRID SAND
MARKLAND
FREYDIS SAND
BJARNI
SNORRI
ALEXIS
?
PRE-MESOZOIC BASEMENT

Figure 3.51 Generalized stratigraphy of the Hopedale Basin (after Umpleby 1979)

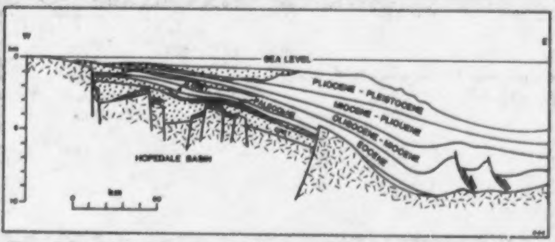

W
E
km
0
5
10
SEA LEVEL
PLIOCENE - PLEISTOCENE
MIOCENE - PLIOCENE
OLIGOCENE - MIOCENE
EOCENE
PALEOCENE
HOPEDALE BASIN
km
0
50

Figure 3.52 Schematic cross-section across Labrador Shelf (Umpleby 1979)

BAFFIN BAY

Area Approximately 305 000 square kilometres from Davis Strait High to Kane Basin. It includes 2000 square kilometres onshore Bylot Island.

Geology The sedimentary geology of offshore Baffin Bay is poorly known but seismic data indicate two areas of relatively thick deposition. At Home Bay, a wedge of Tertiary and possible Upper Cretaceous shales and sandstones, up to four kilometres thick, overlies continental Precambrian and Mesozoic oceanic basements. Tertiary volcanics present in the Davis Strait area, may occur in the subsurface of Home Bay. To the north a depocentre of interpreted Tertiary and Upper Cretaceous sediments, in excess of 12 kilometres in thickness occurs at the mouth of Lancaster Sound. This unit extends westward, across a sill of Paleozoic carbonates, into Lancaster Sound where it is preserved in a half graben, Figure 3.54.

Drilling History There are no wells in this area.

Potential Source Rocks Source rocks have not been identified in Baffin Bay but a small active oil seep is known from a submarine trough in the Scott Inlet area. Significant thicknesses of sediment, including probable marine Tertiary beds, increases the likelihood of some source rocks being present in the northern part of Baffin Bay.

Potential Reservoir Rocks Tertiary and Upper Cretaceous sandstone reservoirs are expected throughout the area as well as lower Mesozoic and Paleozoic clastics and Paleozoic carbonates along the inner shelf.

Known and Potential Hydrocarbon Occurrences No wells have been drilled on the Canadian margin of Baffin Bay. A drilling program off Greenland failed to find any hydrocarbons. Prospects in this area include structures related to basement fault blocks and ridges, possible down-to-basin faults in areas of rapid Tertiary sedimentation and stratigraphic traps along the basin margin.

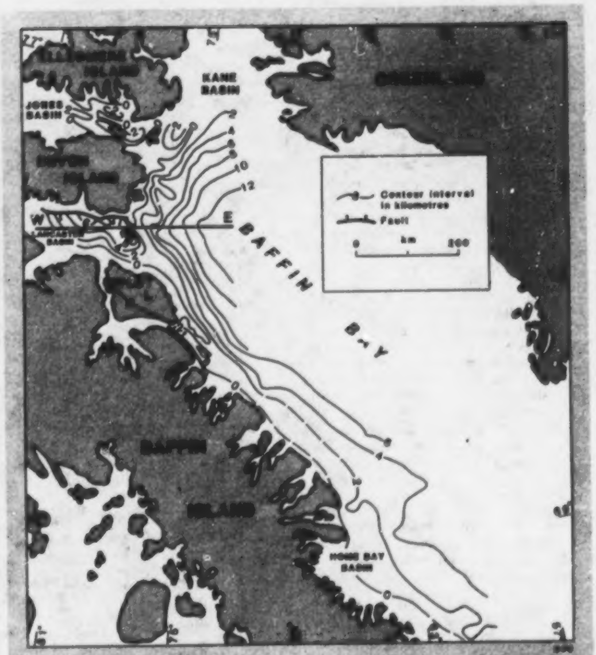

KANE BASIN
JONES BASIN
W
E
BAFFIN BAY
BAFFIN ISLAND
HOME BAY BASIN
0
2
4
6
8
10
12
Contour interval in kilometres
Fault
0
km
200

Figure 3.53 Depth to basement map of Baffin Bay. Zero contour indicates limits of Mesozoic-Cenozoic sediments (after Hea et al 1980)

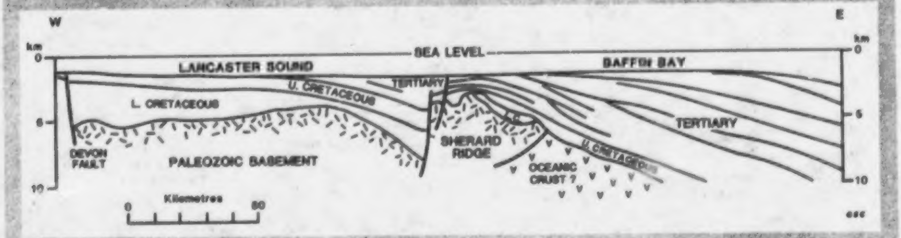

W
E
km
0
5
10
SEA LEVEL
LANCASTER SOUND
BAFFIN BAY
U. CRETACEOUS
TERTIARY
L. CRETACEOUS
DEVON FAULT
PALEOZOIC BASEMENT
SHERARD RIDGE
OCEANIC CRUST ?
U. CRETACEOUS
TERTIARY
Kilometres
0
50

Figure 3.54 Structure section from Lancaster Sound through to Baffin Bay (after Hea et al 1980)

PALEOZOIC BASINS — EASTERN CANADA

Introduction

Between the Western Canada Sedimentary Basin and the basins of the Atlantic offshore, there are several sedimentary regions within or flanking the Canadian Shield. The largest of these is the Paleozoic Hudson Bay Basin within the Hudson Platform. To the south, Paleozoic rocks of the St. Lawrence Lowlands cross southern Ontario and extend northeast along the valley of the St. Lawrence to northwestern Newfoundland. To the east, upper Paleozoic rocks of the successor Maritimes Basins underlie the southern Gulf of St. Lawrence and adjacent areas, Figure 3.55.

Numerous small gas and oil fields occur in peninsular southern Ontario. Two small accumulations, one of gas and one of oil and gas have been discovered in the Magdalen Basin. Estimates of potential have been made for each of the major regions, however, in the case of the Hudson Platform, with only three wells and limited seismic data in more than a 600 000 square kilometres offshore area, this assessment is based on a minimum of geological data.

Reserves

In southern Ontario, the remaining reserves as of 1982 were 836 thousand cubic metres for recoverable oil and 8.8 billion cubic metres for gas.

Potential

Estimates of oil and gas potential for each of the Basins are given in Tables XI. Only southern Ontario can be considered adequately explored. Potential is considered greatest in the Hudson Platform for both oil and gas. Drilling targets for all basins are thought to be small relative to other frontier regions and consequently have had limited and sporadic exploration. The amount of drilling and geophysics in Hudson Bay is too sparse to encourage more active exploration, and the geological understanding of all basins (except southern Ontario) is inadequate to predict the hydrocarbon potential with confidence, hence the speculative values could be significant.

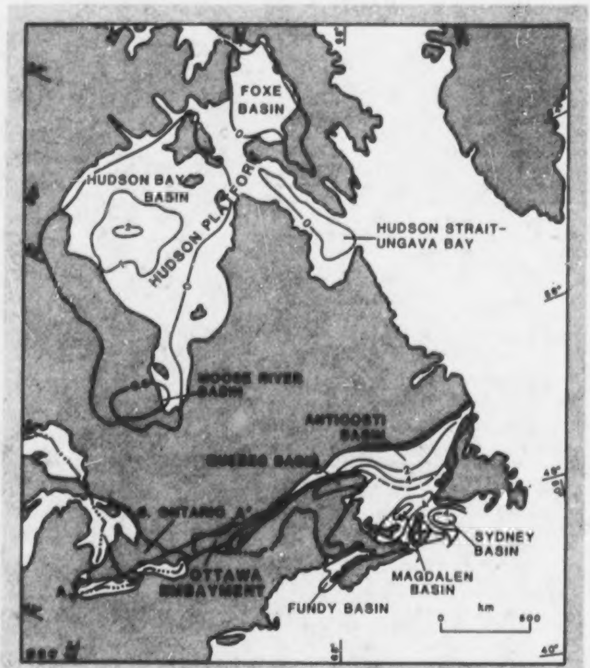

FOXE BASIN
HUDSON BAY BASIN
HUDSON PLATFORM
HUDSON STRAIT-UNGAVA BAY
MOOSE RIVER BASIN
ANTICOSTI BASIN
QUEBEC BASIN
S. ONTARIO
A'
A
OTTAWA EMBAYMENT
SYDNEY BASIN
MAGDALEN BASIN
FUNDY BASIN
km
0
50°
45°
40°
GSC

Figure 3.55 Index map of Paleozoic Basins of Eastern Canada. Contours indicate sediment fill in kilometres

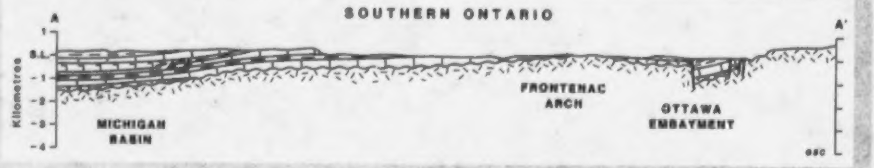

SOUTHERN ONTARIO
A
A'
Kilometres
1
S.L.
-1
-2
-3
-4
MICHIGAN BASIN
FRONTENAC ARCH
OTTAWA EMBAYMENT
GSC

Figure 3.56 Schematic section across southern Ontario

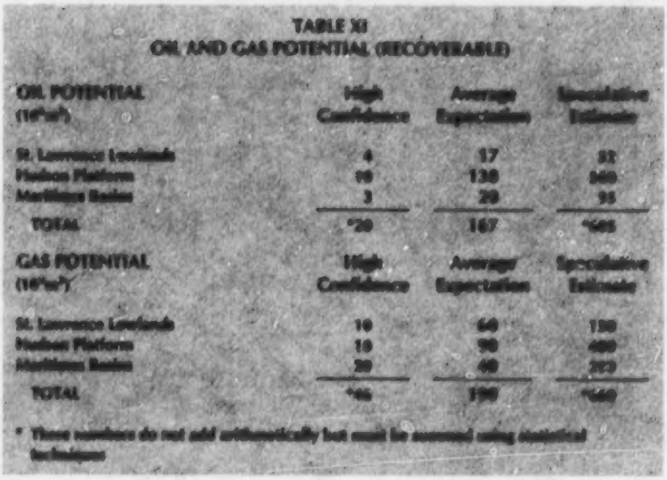


TABLE XI
OIL AND GAS POTENTIAL (RECOVERABLE)

OIL POTENTIAL (10^6m^3)	High Confidence	Average Expectation	Speculative Estimate
St. Lawrence Lowlands	4	17	32
Hudson Platform	10	130	360
Maritimes Basin	3	20	95
TOTAL	*20	167	*505

GAS POTENTIAL (10^9m^3)	High Confidence	Average Expectation	Speculative Estimate
St. Lawrence Lowlands	10	60	130
Hudson Platform	10	90	400
Maritimes Basin	20	40	223
TOTAL	*46	190	*660

* These numbers do not add arithmetically but must be summed using statistical techniques

ST. LAWRENCE LOWLANDS

Area Approximately 293 000 square kilometres of which 160 000 square kilometres is offshore in the Great Lakes and the northern Gulf of St. Lawrence.

Geology Paleozoic rocks extend in a narrow belt from peninsular southern Ontario, along the St. Lawrence River, to the northern Gulf of St. Lawrence and includes Anticosti Island, and parts of Gaspe and northwestern Newfoundland, Figure 3.56. In southern Ontario, the stratigraphy consists of the marginal and shallow marine facies of the adjacent Allegheny and Michigan Basins and includes basal sandstones, shelf carbonates with attendant reef and evaporite facies, and shales. Maximum thickness is less than two kilometres, Figure 3.55. Coeval, but much thicker (up to six kilometres) sequences of carbonates and clastics occur in the Anticosti Basin.

Drilling History Drilling began in southern Ontario in 1858 with discovery of the Oil Springs field. Since then, over 40,000 wells have been drilled. Numerous wells have been drilled along the St. Lawrence River with no significant success. More recently exploration has moved into offshore Lake Erie where more than 1000 wells have been drilled. The Gaspe region has had a long, but sporadic exploration history as has Anticosti Island and Western Newfoundland.

Potential Source Rocks Hydrocarbons in the numerous gas and oil fields in southern Ontario have probably migrated from the adjacent basins but indigenous source rocks may occur in Ordovician marine bituminous shales, and Silurian reefs. In the Anticosti Basin, Ordovician shales and basinal equivalents of the Silurian carbonates are the likely sources of numerous seeps and minor shows.

Potential Reservoir Rocks Sandstones as well as porous carbonates are reservoir rocks in southern Ontario. Similar shelf carbonate and clastic facies have exhibited porosity in the other areas.

Known and Potential Hydrocarbon Occurrences Across southern Ontario, more than a hundred small gas and oil fields occur in rocks ranging from Cambrian to Devonian age. Plays include deformation and updip truncation of Cambrian sandstone and dolomite reservoirs; dolomitization of Ordovician carbonates; updip pinchouts of Lower Silurian sandstones; many Upper Silurian pinnacle and patch reefs, Figure 3.57 and dolomitization of Middle Devonian carbonates. Oil seeps were recorded as early as 1812 in western Newfoundland and 1836 in Gaspe. Subsequent drilling in both areas recorded only small non-commercial accumulations.

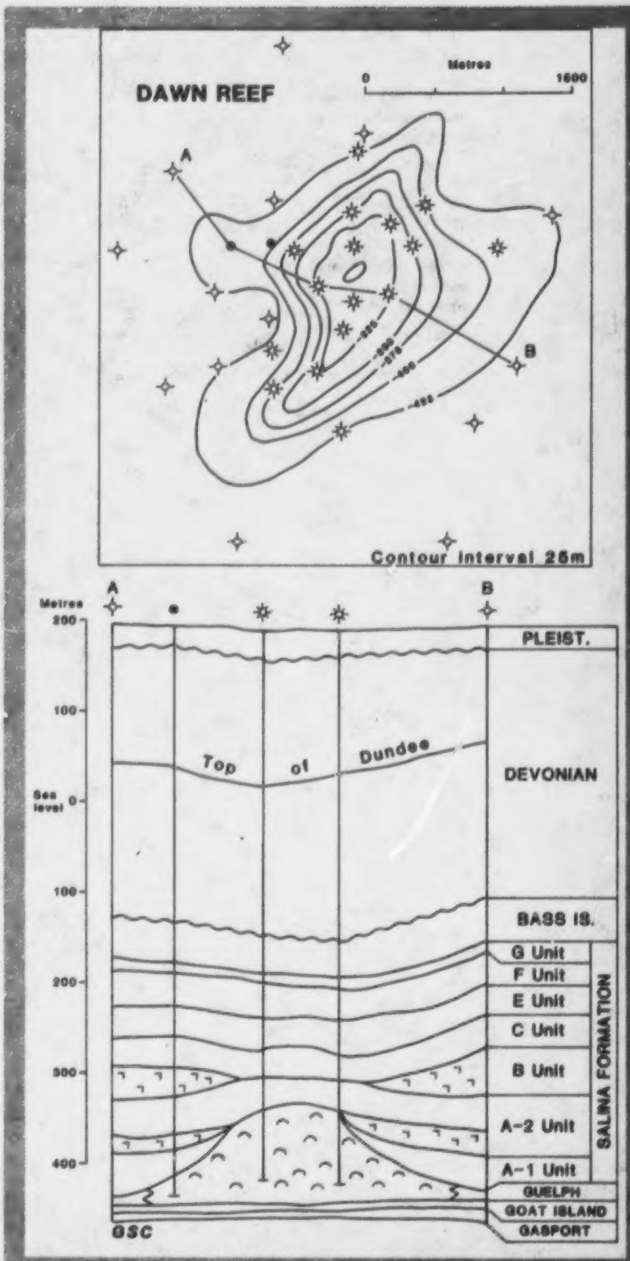


Figure 3.57 Structure map and section of the Dawn Reef of southern Ontario, typical of the small patch reef type of trap

HUDSON PLATFORM

Area Approximately 100 000 square kilometres of which less than a third is onshore.

Geology The Paleozoic rocks of the Hudson Platform are contained in four large but shallow depressions within the Canadian Shield, Figure 3.55. The outcrop patterns indicate these are erosional remnants of a much broader original cratonic cover, Figure 3.59. All are essentially carbonate basins with a variety of facies including small reefs. Some shales, evaporites and sandstones also occur, Figure 3.58. Maximum sedimentary thickness occurs in Hudson Bay Basin where up to two kilometres of sedimentary rocks are known.

Drilling History Several holes were drilled in the onshore areas of the Moose River and Hudson Bay Basins in the 1940's. In 1969, Aquitaine *et al* Walrus was drilled in the offshore. Two additional wells were drilled offshore in 1974. There has been one well drilled in both Foxe Basin and Ungava Bay.

Potential Source Rocks There are no known oil seeps from the rocks in the Hudson Platform although bitumen has been reported from vugs associated with Ordovician reefs. Intervals of black petroliferous shale occur within the Ordovician and Devonian successions. The latter yielded 18 litres per tonne on distillation. There were traces of oil and gas reported from two of the offshore wells although thermal maturation of organic matter appears very low.

Potential Reservoir Rocks The main reservoir beds will be intercrystalline vuggy or reefoid intervals within carbonate formations with seal provided by tight carbonates, shale or evaporite facies.

Known or Potential Hydrocarbon Occurrences There are no known hydrocarbon reserves in this area. Plays would include structures related to basement uplifts, faults, salt, drape over reef buildups, etc. With random porosity developed within regional carbonate formations, stratigraphic traps will be common.

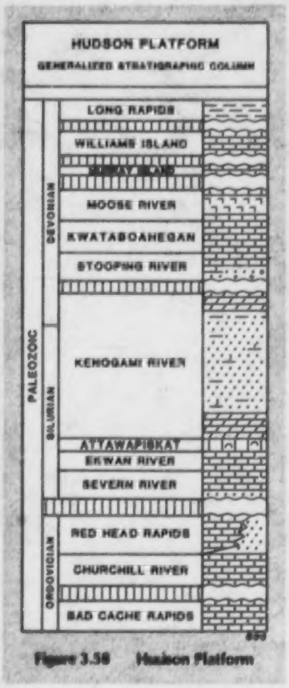

HUDSON PLATFORM
GENERALIZED STRATIGRAPHIC COLUMN
PALEOZOIC
DEVONIAN
SILURIAN
ORDOVICIAN
LONG RAPIDS
WILLIAMS ISLAND
MOOSE RIVER
KWATABOAHEGAN
STOOPING RIVER
KENOGAMI RIVER
ATTAWAPISKAT
EKWAN RIVER
SEVERN RIVER
RED HEAD RAPIDS
CHURCHILL RIVER
BAD CACHE RAPIDS

Figure 3.58 Hudson Platform

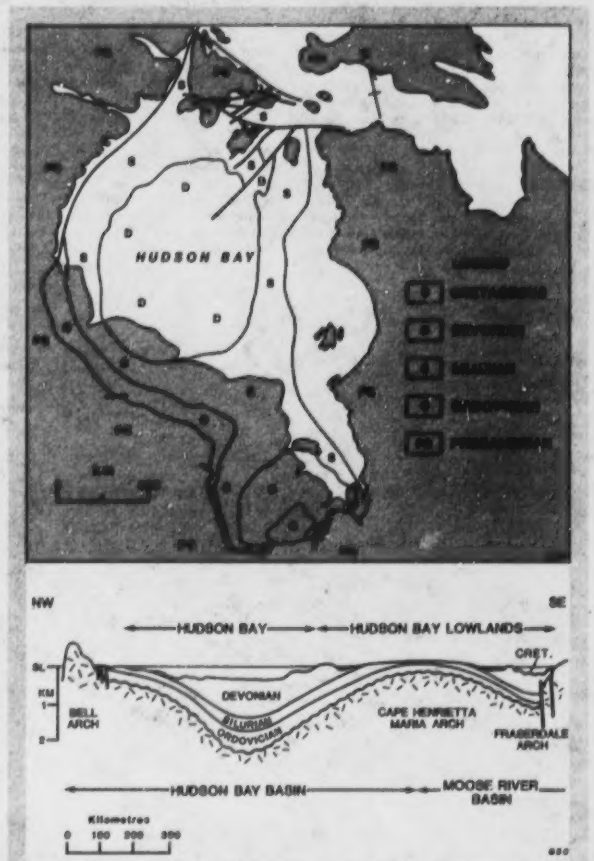

HUDSON BAY
S
D
NW
SE
HUDSON BAY
HUDSON BAY LOWLANDS
CRET.
SL
KM
1
2
BELL ARCH
DEVONIAN
SILURIAN
ORDOVICIAN
CAPE HENRIETTA MARIA ARCH
FRASERDALE ARCH
HUDSON BAY BASIN
MOOSE RIVER BASIN
Kilometres
0
100
200
300

Figure 3.59 Geological map of Hudson Bay-James Bay with structure section (Sanford and Norris 1973)

MARITIMES BASINS

Area Approximately 225 000 square kilometres of which about one third is onshore.

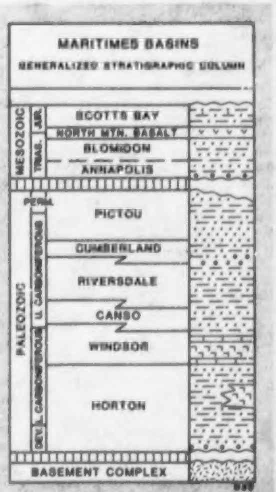
Geology This area includes three major elements; the Magdalen Basin with up to nine kilometres of Upper Devonian to Permian sediments; the Fundy Basin with more than six kilometres of probable Carboniferous to lowermost Jurassic sediments; and the Sydney Basin with up to five kilometres of Carboniferous rocks, Figure 3.61. The oldest formations are largely coarse to fine-grained, red continental clastics succeeded by evaporites and some limestone beds, all of Early Carboniferous age. These are overlain by thick continental red and grey sandstone-shale sequences of Late Carboniferous age and locally thin Permian red beds. A thick wedge of Upper Triassic – lowermost Jurassic continental red beds unconformably overlies the Paleozoic rocks in the Fundy Basin, Figure 3.60.

Drilling History Reliable statistics on early oil and gas exploratory drilling in these areas are not readily available. Between 1970 and 1980, nine wells were drilled in the offshore areas of these basins, six in Magdalen Basin, two in the Sydney Basin and one in the Fundy Basin.

Potential Source Rocks The formations in these areas are almost entirely continental and contain mostly terrestrial organic matter. Also many of the sequences are thermally over-mature indicating gas as the most likely hydrocarbon. An exception is a local occurrence of Early Carboniferous petroliferous lacustrine beds which have generated gas, oil, and the solid bitumen Albertite.

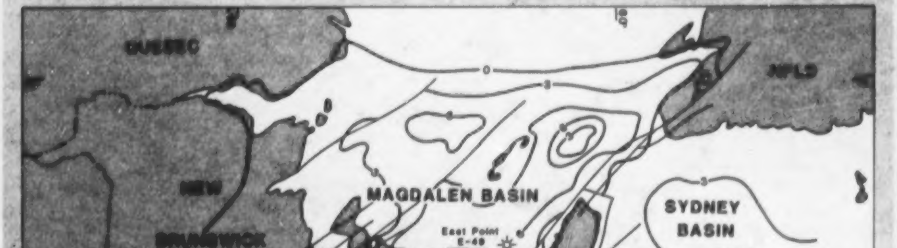
Potential Reservoir Rocks Formations in these basins are dominated by continental sand and shale sequences which contain good reservoir beds with the intervening shales providing seals.

Known and Potential Hydrocarbon Occurrences The small oil and gas field at Stony Creek New Brunswick, was discovered in 1909. In 1974, an exploratory well, East Point, in the Gulf of St. Lawrence tested a small gas accumulation in a Late Carboniferous sandstone reservoir over a large salt structure. Two wells drilled in the Sydney Basin in 1974 and 1976 encountered very minor gas shows in a basal conglomerate. Plays in all these basins will be associated with a variety of basement and salt structures, and stratigraphic traps.



MARITIMES BASINS
GENERALIZED STRATIGRAPHIC COLUMN
MESOZOIC
JUR.
TRIAS.
SCOTTS BAY
NORTH MTN. BASALT
BLOMIDON
ANNAPOLIS
PALEOZOIC
PERM.
U. CARBONIFEROUS
L. CARBONIFEROUS
DEV.
PICTOU
CUMBERLAND
RIVERSDALE
CANSO
WINDSOR
HORTON
BASEMENT COMPLEX

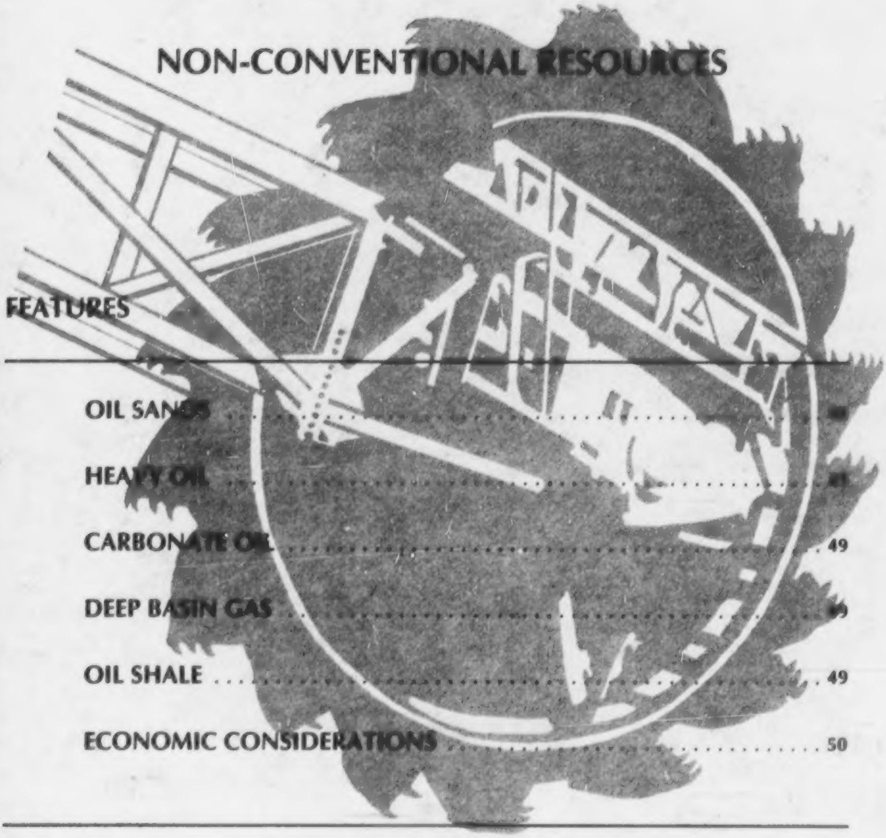
Figure 3.60 Maritimes Basins



QUEBEC
NFLD
NEW BRUNSWICK
U.S.A.
MAGDALEN BASIN
East Point E-49
SYDNEY BASIN
FUNDY BASIN
NOVA SCOTIA
0
3
6
Fault
Kilometres
0
200
44°
44°
60°
66°

Figure 3.61 Sediment fill map of Maritimes Basins. Contours in kilometres

NON-CONVENTIONAL RESOURCES



FEATURES

OIL SANDS .... [illegible]

HEAVY OIL .... [illegible]

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OIL SHALE 49

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NON-CONVENTIONAL RESOURCES

Introduction

In addition to Canada's conventional oil and gas resources, major accumulations exist in a non-conventional category. These include oil sands, heavy oil, carbonate oil, "Deep Basin" gas, and oil shale. These resources are termed nonconventional in that they cannot be produced effectively by normal oilfield techniques. These resources are commonly viewed as potential oil and gas but differ from other potential resources in that they have been discovered. Their extent, location and quantity are well defined and the major impediment to their development is the cost of extraction, and development of new technology to reduce those costs.

Oil Sands

Canada's largest and best known oil sands occur in Lower Cretaceous sandstones in Alberta. Although commonly called the Athabasca oil sands, they occur in several separate deposits (Figure 4.1) with a common geological setting. Sandstones and shales of the Lower Cretaceous (Mannville Group) were derived from both the shield area to the east and from orogenic activity in the west. The sands were transported to the Alberta Basin by a series of rivers and deposited in a complex of fluvial-deltaic non-marine to marine environments. Extensive oil generation, migration and trapping has formed the oil sands which are among the largest oil accumulations in the world. The oil in these sands occurs as bitumen and behaves essentially as a solid unless heated. About 10% of the total deposits crops out at the surface and methods of open-pit mining have been developed. The remainder occurs at depths to 1 000 metres. These latter deposits will probably be developed by in-situ processes using steam and other techniques similar to those of enhanced oil recovery.

Quantities of in-place crude bitumen contained in the oil sands according to the Energy Resources Conservation Board of Alberta are:

	$(10^6 m^3)$
Athabasca	152 640
Buffalo Head Hills	920
Cold Lake	32 590
Peace River	11 440
TOTAL	197 590

To date, the two operating mines, Suncor and Syncrude, have processed 65 million cubic metres of crude bitumen which after refining amounts to production of 46 million cubic metres. Established remaining reserves of synthetic crude oil are currently listed as 3 860 million cubic metres.

Oil sands are also known to exist in Triassic sandstones on Melville Island. The deposit is considerably smaller than those in Alberta but probably contains more than 500 million cubic metres of bitumen in-place.

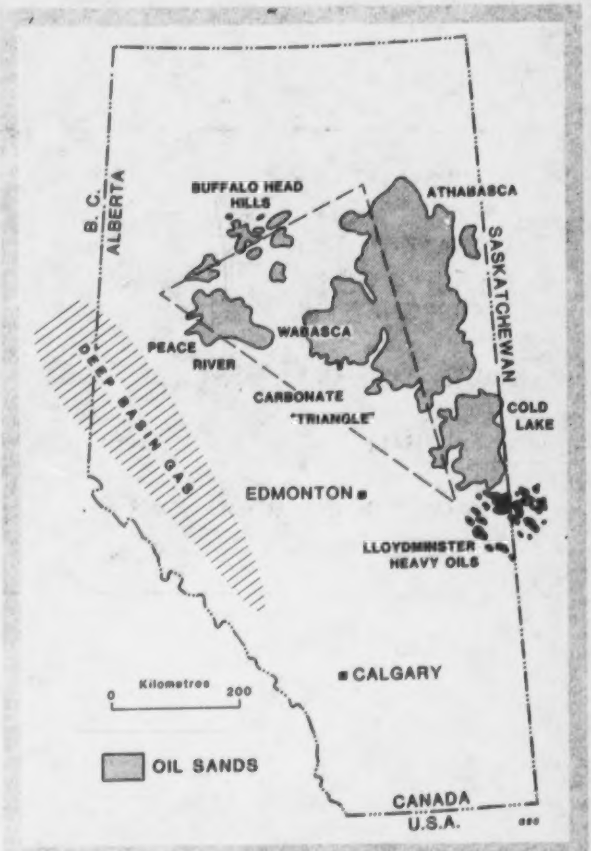


Figure 4.1 Index map. Location of oil sands, deep basin gas, heavy oil, and carbonate oil

Heavy Oil

Deposits of heavy oil in the Lloydminster area are included here as non-conventional even though they have a small component that can be produced conventionally. However, the total percentage of the resource likely to be recovered conventionally is small, and significant future production will have to rely on non-conventional techniques. The heavy oil deposits occur in the same geological setting as the oil sands except that the depositional environment has been dominantly fluvial-intertidal, resulting in a series of thin discontinuous cyclic sand-shale sequences. Individual sandstone beds contain net-pay in the five to ten metre range on average, and occur at depths of about 1000 metres. The gravity of the Lloydminster type oils is higher than in the nearby Cold Lake oil sands and varies from 13° to 18° API.

Total heavy oil in-place, based on extensive geologic analysis, is estimated to be 5 200-7 460-10 630 million cubic metres for high confidence — average expectation and speculative estimates respectively. If the total reserve is restricted to "rich" oil, (thicker beds, high oil saturation, no underlying water, etc.), these values reduce to 2 380-3 010 and 3 650 million cubic metres. The resource is divided almost equally between Alberta and Saskatchewan, and is being actively examined in many fields for application of enhanced recovery methods. Estimates of the total percentage of the resource which will be recoverable are highly cost-price dependent and are not included in this report.

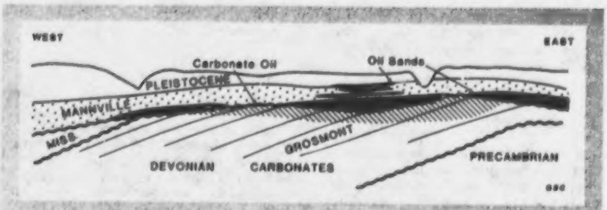


Figure 4.2 Schematic section illustrating trapping of bitumen in oil sands and carbonates

Carbonate Oil

Crude bitumen accumulations are known to exist in carbonate rocks of Devonian and Carboniferous age that subcrop beneath the Alberta oil sands (Figure 4.2). Early estimates of total bitumen in-place were of the same magnitude as that of the oil sands, but very little is known about most of the accumulations in what has been termed the "carbonate triangle" (Figure 4.1). One unit, the Grosmont Formation, is considered to contain the most crude bitumen and has the best reservoir properties for potential development. The Energy Resources Conservation Board of Alberta has designated in-place crude bitumen reserves of 50 million cubic metres to the Grosmont Formation as of December, 1981. The Grosmont accumulations occur at depths of 200 to 500 metres and development will have to rely on in-situ recovery processes.

Deep Basin Gas

Gas resources in quantities as large as Canada's existing reserves are said to exist in the "Deep Basin" of western Alberta and adjacent British Columbia (Figure 4.1). These so-called "tight gas" resources are non-conventional in the sense that they exist down-dip from regional water, and in rocks of very low porosity with ultra low permeability (Figure 4.3). Large scale exploitation of these resources would also be non-conventional, dependent on massive hydraulic fracturing of the section to enable effective drainage. Some of the deep basin gas is in connection with conventional sandstone and conglomerate reservoirs, as in the Falher sands of Cretaceous age in the Elmworth gas field. At Elmworth, some ten billion cubic metres of "tight gas" are considered to be in contact with conglomerates and assigned as reserves. The Geological Survey of Canada has not yet evaluated deep basin "tight gas" potential, which occurs from Permian through Cretaceous units, but industry estimates as high as 8 500 billion cubic metres of gas have been published.

Oil Shale

Canada's oil shale deposits are widely distributed across the country and occur in rocks from Ordovician to Cretaceous age (Figure 4.4). Oil shales actually include a variety of fine-grained sedimentary rocks containing indigenous organic matter that is mostly insoluble in petroleum solvents, and from which shale oil can be extracted by pyrolysis. The organic matter is usually kerogen, an insoluble solid organic material, and lesser amounts of bitumen. The organic material has been derived primarily from algae and spores incorporated into fine-grained sediments.

Carboniferous oil shales of the Albert Formation in New Brunswick are the best known and delineated of Canada's deposits. These deposits are similar lithologically to the famous Green River Shales of Colorado, which are considered economically exploitable. The New Brunswick deposits occur from surface to 615 metres depth. Some intervals contain more than 100 litres of shale oil per tonne of rock. Published reserves are estimated as in

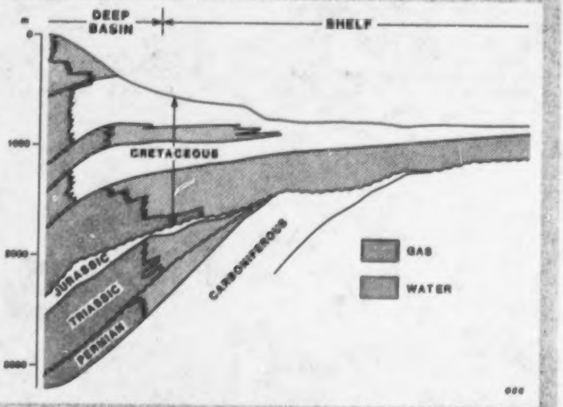


Figure 4.3 Schematic section of tight gas trapped by permeability barriers below water zone

excess of 45 million cubic metres in-place. Except for the New Brunswick deposits, there is insufficient data upon which to base estimates of potential resources.

Economic and Environmental Considerations

Oil Sands The oil sands of Alberta potentially represent energy supplies having no exploration cost. The cost of recovering these resources is a function of the thickness of overburden and/or depth of deposits as well as their pay thickness and quality. Economic evaluation reveals an encouraging comparison of the investment cost per cubic metre (capital investment per cubic metre of recoverable reserves) for these bitumen projects when compared to the development of frontier oil discoveries. Current estimates show that surface mining and in-situ bitumen projects have an investment cost ranging from $20 - $45 per cubic metre of recoverable reserves in 1983 dollars. This compares to $25 - $35 per cubic metre for East Coast development in water depths of less than 100 metres and $40 - $60 per cubic metre for shallow Beaufort Sea developments. However, it must be noted that operating costs for oil sands projects are higher than those for conventional oil operations. Surface mining of oil sands leaves substantial residuals as solid wastes including overburden, and air and water pollutants. Environmental residuals are generally lower for in-situ operations. However, the processing facilities for in-situ operations could contribute to air and water pollution. Mitigation of these undesirable pollutants imposes additional costs.

Deep Basin Gas Tight formation gas is produced from reservoirs with an average permeability of less than 1 millidarcy. Additional costs are incurred in formation fracturing to increase productivity and because of the depths to which these wells are drilled. The gas, however, is sweet and does not require complex processing, and also is accessible to pipeline. No particular environmental hazards are posed.

Oil Shale Costs of oil shale development depend largely on the extraction process. Oil shale can be mined and then processed on the surface, or it can be processed underground (in-situ) and the resulting liquids withdrawn by wells. The drilling, blasting, and excavation technologies applicable to surface coal mining also apply to surface oil shale mining, except that oil shale zones can be very thick and considerably harder than coal seams. The in-situ approach involves fracturing the oil shale underground, introducing heat to cause pyrolysis underground, and collecting and withdrawing the shale oil, through wells, to the surface for upgrading. Upgrading is accomplished by reducing the viscosity, sulphur and nitrogen content of the shale oil. The primary tradeoff in transportation will be between the added cost of transportation of the oil prior to upgrading versus the cost of decentralized refining at each retorting site.

With regard to environmental concerns, surface mining of oil shale leaves many residual air and water pollutants, solid wastes plus overburden, and results in land consumption and reclamation. Environmental residuals are generally lower in underground mines and for in-situ operations than in surface mines, particularly for solid wastes. However, the necessary upgrading or processing facilities would have added costs due to air and water pollution controls and the handling of hot oil production.

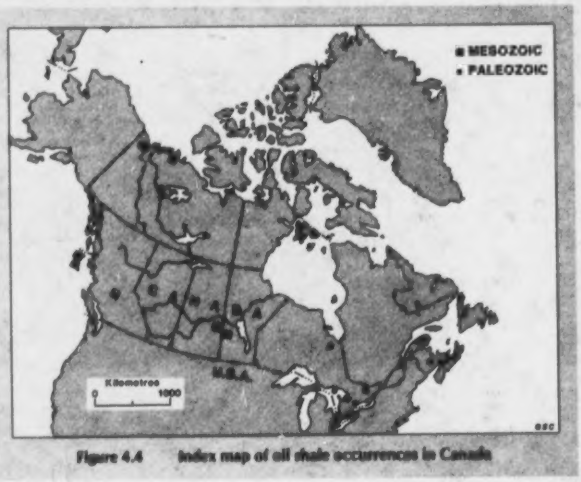
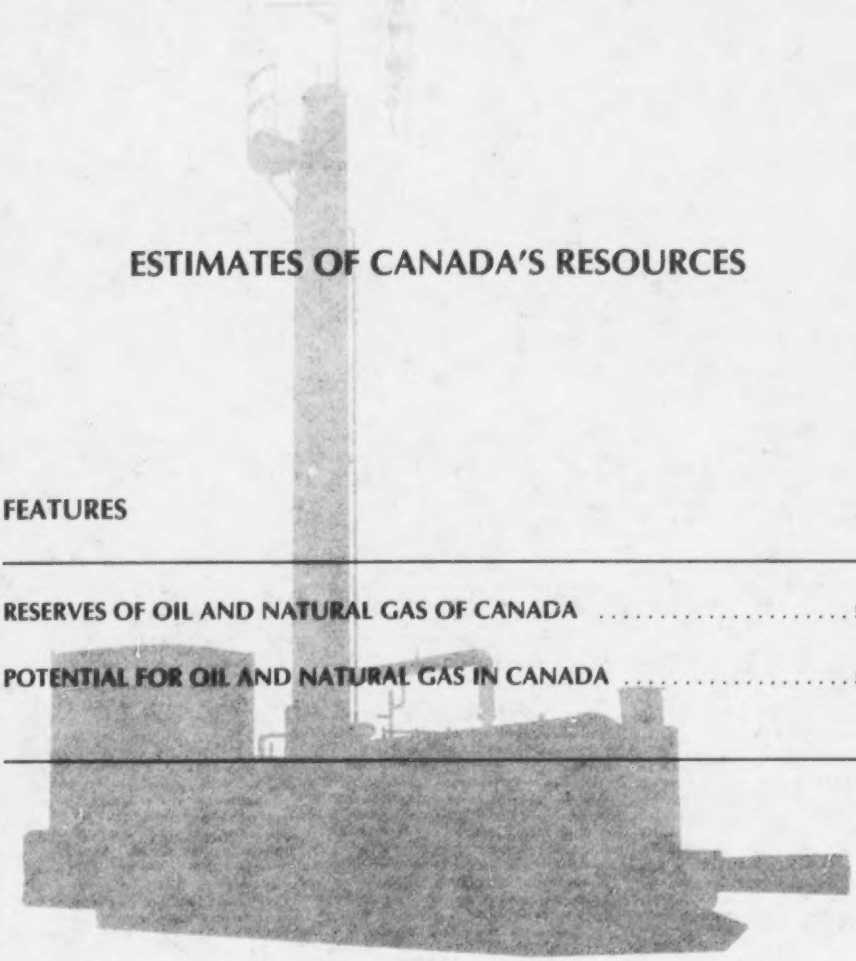


Figure 4.4 Index map of oil shale occurrences in Canada



ESTIMATES OF CANADA'S RESOURCES

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RESERVES OF OIL AND NATURAL GAS OF CANADA 52

POTENTIAL FOR OIL AND NATURAL GAS IN CANADA 53

RESERVES

TABLE XII
REMAINING RESERVES AND DISCOVERED RESOURCES OF CANADA
(Recoverable)

	OIL ($10^6 m^3$)	GAS ($10^9 m^3$)
WESTERN CANADA SEDIMENTARY BASIN	754	2111
BEAUFORT SEA-MACKENZIE DELTA	117*	286*
ARCTIC ISLANDS	76*	361*
EASTERN CANADA-OFFSHORE	225*	246*
PALEOZOIC BASINS-EASTERN CANADA	1*	9*
TOTAL	1173	3013

* Best current estimate of discovered resources

Conventional Oil and Gas Reserves

The most recent estimates of remaining established reserves prepared by the National Energy Board (NEB) as of year end 1981 are indicated in Table XII for the Western Canada Sedimentary Basin. These values have been adjusted modestly to incorporate slight differences in reserves in the District of Mackenzie estimates provided by the Resource Evaluation Branch, a unit of the Canada Oil and Gas Lands Administration (COGLA). Best current estimates of discovered resources in the frontier regions were supplied by COGLA and are indicated in Table XII. Estimates of reserves shown for the Paleozoic Basins of Eastern Canada (all in Southern Ontario) are from the Canadian Petroleum Association.

The distinction between established reserves and best current estimates of discoveries cannot be overemphasized. The established reserves can be viewed as rigorously quantified amounts of oil and gas that can be produced with identified economics with high certainty. The best current estimates, on the other hand, are commonly based on a single well per discovery plus best available geological-engineering judgement. Such estimates are subject to major revision. The economic viability of discovered resources in frontier basins is at this time uncertain. The inclusion of both types of reserves in Table XII is for convenience of comparison and does not imply equality of confidence in the estimates.

The tabulation of reserves indicates that although important discoveries have been made in each of the frontier regions, the bulk of discovered resources exist in the Western Canada Sedimentary Basin. This is particularly true for gas reserves which have grown significantly since the last report, EP 77-1. Oil reserves of Western Canada have declined from 1175 million cubic metres reported in EP 77-1; this decline being slightly less than the amounts discovered in frontier regions in the same time period.

Non-Conventional Oil and Gas Reserves

All of the resources indicated in the chapter on Non-Conventional Resources could be counted as reserves in the sense that they have been discovered and their distribution is known with some high level of confidence. However, because the quantities that can ultimately be produced from these resources is totally dependent on as yet uncertain costs and future technology, only a small amount can be considered equivalent to the reserves indicated in Table XII. The established remaining reserve estimate of synthetic crude oil of 3 860 million cubic metres as of year-end 1981 (Energy Resources Conservation Board of Alberta) represents reserves of oil sands in the mining area known to be economically viable at this time.

Enhanced Oil Recovery

A category of oil potential that has not been discussed elsewhere in this report is additional oil that may be recovered from existing and potential oil pools by the introduction of enhanced oil recovery techniques. These techniques include a wide variety of processes, many of them experimental, designed to recover oil left behind in the reservoir after primary and secondary (waterflood) production. Methods include the introduction of chemicals, steam stimulation and floods, carbon dioxide floods, and wet and dry thermal stimulation.

Introduction of enhanced recovery methods usually requires very detailed reservoir characterization, computer modelling of the proposed process and small scale (pilot) field trial before actual field development. The final field application usually involves much closer well spacing than that used in primary-secondary recovery. The total process from design to first production may take five to ten years. All of these considerations contribute to the difficulty of predicting potential quantities of oil that will result from enhanced recovery. The Geological Survey's current estimate of enhanced oil recovery potential from Western Canada was prepared in 1978 and suggests a range of 160-500-950 million cubic metres of potential for high confidence, average expectation and speculative values respectively.

POTENTIAL

Table XIII
OIL AND GAS POTENTIAL OF CANADA
(Recoverable)

OIL POTENTIAL (10^6m^3)	High Confidence	Average Expectation	Speculative Estimate
WESTERN CANADA SEDIMENTARY BASIN	234	593	1210
CORDILLERAN BASINS	—	50	110
BEAUFORT SEA-MACKENZIE DELTA	307	1347	2962
ARCTIC ISLANDS	316	686	1305
EASTERN CANADA OFFSHORE	512	1877	3392
PALEOZOIC BASINS-EASTERN CANADA	20	167	605
TOTAL	*1486	4720	*8995

GAS POTENTIAL (10^9m^3)	High Confidence	Average Expectation	Speculative Estimate
WESTERN CANADA SEDIMENTARY BASIN	1544	2504	4930
CORDILLERAN BASINS	40	270	760
BEAUFORT SEA-MACKENZIE DELTA	871	1865	4103
ARCTIC ISLANDS	1100	2257	3662
EASTERN CANADA OFFSHORE	725	2423	4713
PALEOZOIC BASINS-EASTERN CANADA	46	190	660
TOTAL	*4342	9509	*18285

* These numbers do not add arithmetically but must be summed using statistical techniques

Conventional Resources

Quantities of oil and gas estimated to exist in the six petroleum regions of Canada are listed in Table XIII. The values of estimates are indicated as recoverable in the sense of technically recoverable with neither economic constraints nor concern of whether and when the resources may be discovered. Accordingly, the reader is cautioned that potential resources are undiscovered and must not be regarded with the same confidence as estimates of reserves.

Oil potential is estimated to be greatest in the Eastern Canada Offshore Region at both average and speculative values. Expectations are strongly focussed at the region surrounding the giant Hibernia discovery and in small basins to the east. The Beaufort Sea-Mackenzie Delta region ranks second in terms of oil potential, with numerous discoveries already made but as yet poorly defined. The largest remaining potential is expected to occur in intermediate to deep water parts of the Beaufort Sea. The oil potential described for Western Canada will probably occur in much smaller fields than those in the frontiers, but will have the advantage of economic viability and relative ease of exploration.

Gas potential is estimated to be more-or-less equal for each of the frontier regions and the Western Canada Sedimentary Basin, particularly at the average expectation level of confidence. Giant or near giant-sized discoveries have already been made in each of the frontier regions and additional large-sized discoveries can be confidently predicted. The logistical difficulties of development, and consequent costs will ultimately determine which of the regions will contribute most to future supply. The tendency in Western Canada will be for somewhat smaller discoveries, but major fields are estimated to exist albeit with lesser confidence.

Non-Conventional Resources

Quantities of non-conventional resources estimated to exist in Canada dwarf those of the conventional category. They qualify as potential in that their inclusion with established recoverable reserves would certainly present a distorted view. The very large in-place resource estimates have limited meaning until they can be described in an economic context. Of the several categories of non-conventional resources described earlier, the greatest promise for future potential lies in the oil sands and heavy oil deposits. Several additional open-pit mining operations of the same magnitude as the existing two could be developed. Smaller scale in-situ development in the Cold Lake deposit is equally promising and could contribute significant production. Extensive development of the Lloydminster-type heavy oils represents a much smaller scaled series of operations. All of these options are highly sensitive to cost and price consideration.

CONCLUSIONS

Conventional Resources

Canada's potential oil and natural gas resources are large and could ensure self-sufficiency if means can be found to convert a significant portion of them into economic reserves. The potential for future discovery is greater in the frontier regions than in western Canada. This is due to the degree of exploration maturity of the Western Canada Sedimentary Basin.

The portion of these resources that is, or will be, commercially viable depends on prevailing economic conditions as affected by technological progress in development, production and transportation. To date there has been no consensus regarding specific development, production and transportation systems suitable for frontier discoveries, particulary for offshore areas. This has hampered the ability to estimate the contribution that frontier resources can make to future Canadian energy supplies. The Department is working towards providing estimates that can be used with a reasonable degree of confidence.

The pace of exploration, and therefore the rate at which frontier resources are discovered, will be affected by factors that include exploration success; expectations regarding market prices, development and operating costs; prevailing fiscal regimes; technological progress; and successful commercial exploitation of discoveries already made. Lead times from discovery to commercial development are long in frontier regions and it is unlikely that large-volume frontier production will be available to Canadian markets until the 1990's.

For the balance of this decade therefore, domestic oil supply will have to depend primarily on western Canada reserves. Infrastructure already in place in this area ensures that newly-found conventional reserves can be quickly placed on production, however more intensive exploration efforts will be needed to accelerate discovery. Enhanced recovery of existing light and medium crude oil reserves and of heavy crude oil can, as well, make a substantial contribution to supply over this period.

Oil supply beyond 1990 will likely include production from frontier discoveries in the East Newfoundland Shelf, Arctic and the Beaufort Sea regions. Given the appropriate economic climate, additional in-situ oil sands projects, surface mining oil sands plants, heavy oil and an increasing quantity of enhanced recovery supply can also be viewed within this time-frame, as well as a continuing contribution from conventional oil from the Western Canada Basin.

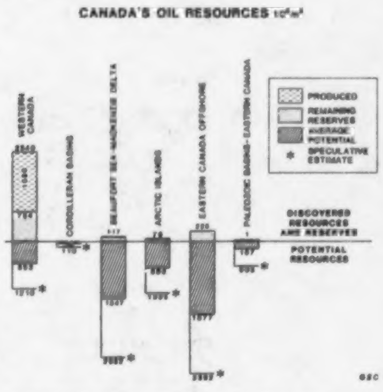

Figure 6.1 Bar chart, Conventional Oil Resources of Canada

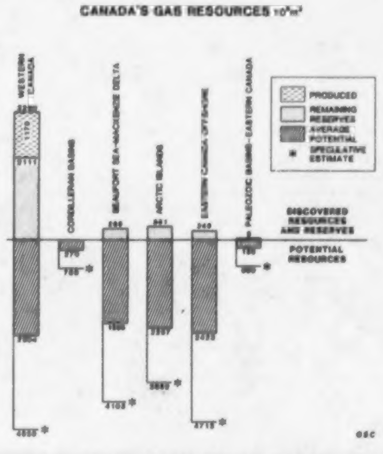

Figure 6.2 Bar chart, Conventional Gas Resources of Canada

In addition to development of oil deposits already taking place in the Mackenzie Corridor, pipeline access to the northern frontiers would open other oil resources of the Mackenzie Corridor to southern markets.

Gas potential estimated in all frontiers plus western Canada, in addition to present reserves, indicates an assured supply. These resources should meet current requirements as well as expansions of Canadian gas markets for the foreseeable future. This will, of course, require development investments to maintain and expand delivery capacity from western Canada.

Major current limitations on frontier gas development are high development, operating and transportation costs, and lack of markets. In addition, remote frontier projects face technological and environmental hurdles.

Non-Conventional Oil Resources

The future mix of non-conventional and conventional resources in supplying domestic energy requirements will depend on the relative costs of exploration, development, operation and delivery to market.

Canada has a large potential supply of oil from heavy oil reservoirs and oil sands deposits. These resources represent a known source of supply, probably exceeding conventional oil resources in terms of quantity ultimately producible. Available upgrading technology together with development and operating costs are the limiting factors in bringing these supplies to the Canadian market. Although the technology for heavy oil and bitumen extraction exists at this time, a full realization of the potential from in-situ recovery and heavy oils will require advances in upgrading technology. Small scale upgrading projects could allow technology demonstration and improvements and hopefully will lead to larger scale projects.

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GLOSSARY OF TERMS

allochthonous: Formed elsewhere than its present place.

basement: The undifferentiated complex of rocks that underlie the rocks of interest in an area.

basin analysis: The study of all aspects of geoscience and their interrelationships for a depositional basin.

bathyal: The environment of deposition in deep water between 200 and 2000 metres now largely confined to the outer continental slopes.

bioherm: A moundlike or reeflike mass of rock built up by sedentary organisms.

biostrome: A distinctly bedded extensive mass of rock built by, or made up of, the remains of sedentary organisms.

bitumen: A generic term applied to a solid composed principally of a mixture of hydrocarbons substantially free of oxygenated bodies.

conventional oil and gas: Oil and gas wholly or in part recoverable from a well using standard techniques.

craton: A part of the earth's crust that has attained stability, and has been little deformed for a prolonged period.

depocentre: An area or site of maximum deposition.

diapir: A dome or anticline in which the overlying strata have been ruptured by the intrusion of underlying plastic materials.

epeirogenic: Primarily vertical movements (up or down) of large parts of continents.

epicontinental sea: Situated on the continental interior.

eustatic: Pertaining to worldwide changes of sea level that affect all oceans.

evaporite: A nonclastic sedimentary rock composed primarily of minerals produced from a saline solution as a result of evaporation.

exploration play: A group of similar exploration prospects postulated or proven to contain oil and, or natural gas, i.e. a group of genetically related prospects or pools. A play may contain both discovered pools and conceptual prospects as yet undrilled.

facies: The aspects, appearance, and characteristics of a rock unit, usually reflecting the conditions of its origin.

listric: A usually concave upward surface of fracture.

melange: A body of rock characterized by the inclusion of fragments and blocks of all sizes, both local and exotic, embedded in a sheared matrix.

miogeocline: A prograding wedge of shallow water sediment at the continental margin or along a geosynclinal seaway.

natural gas liquids (NGL's): Hydrocarbons generally produced in association with natural gas, and recoverable as liquids, including propane, butane, and pentanes plus.

orogenic: Related to the process of mountain building.

palinspastic: The process of restoring features to their original spatial positions prior to deformation.

paralic: Pertaining to intertongued marine and continental deposits laid down on the landward side of the coast or in shallow water subject to marine invasion.

prodelta: That part of the delta that is below the effective depth of wave erosion.

prospect: A geological configuration (e.g. a structure defined geophysically)conceived to have trapped petroleum that forms a target for drilling.

salt pillow: An embryonic salt dome rising from its source bed, still at depth.

sebkha: A supratidal environment of deposition formed under arid conditions on restricted coastal plains just above high tide level.

subcrop: A subsurface contact that describes the areal limit of a formation beneath an unconformity.

subduction: The process of one lithospheric plate descending beneath another.

syntectonic: A geologic process or event occurring during a period of tectonic activity.

terrane: A crustal fragment characterized by a distinctive, laterally persistent stratigraphic record that differs from the coeval records in neighboring terranes, from which it is separated by major faults and, or structurally complex zones.

turbidity flow: A tongue-like flow of dense sediment laden water moving down a slope.

vesicles: Cavities of various shapes in lava formed by the entrapment of gas bubbles during solidification.

vug: A small cavity in rock commonly lined with crystals.

Senator MURKOWSKI. Our first witness today is the Honorable Eric Evered, the Administrator of the Energy Information Administration.

I welcome you, Mr. Evered, to the hearing, and would ask that you please proceed.

We look forward to your testimony.

STATEMENT OF HON. J. ERICH EVERED, ADMINISTRATOR, ENERGY INFORMATION ADMINISTRATION, DEPARTMENT OF ENERGY

Mr. EVERED. Mr. Chairman, I am pleased to appear before the subcommittee today to provide an overview, a background, on North American natural gas reserves and resources.

I would suggest that my full prepared testimony with attachments, which is admittedly exhaustive per instructions of subcommittee staff, be made a part of the hearing record.

Senator MURKOWSKI. It will be entered into the record, and if it is truly an inhaustive supply, why we'll either have to get more staff, or they'll have to work longer.

Mr. EVERED. In view of that, I will be pleased—shall I say relieved—to summarize my presentation.

Senator MURKOWSKI. That's mutual. [Laughter.]

Mr. EVERED. Mr. Chairman, standard definitions of natural gas reserve and resource terms have not been universally adopted. Therefore, it's not surprising that a great deal of confusion surrounds the use and understanding of the data which describe these quantities.

With your permission, I'll use this first chart, chart 1, to illustrate quickly the relationships among the most important reserve and resource terms.

Relationship of Natural Gas Reserve and Resource Terms

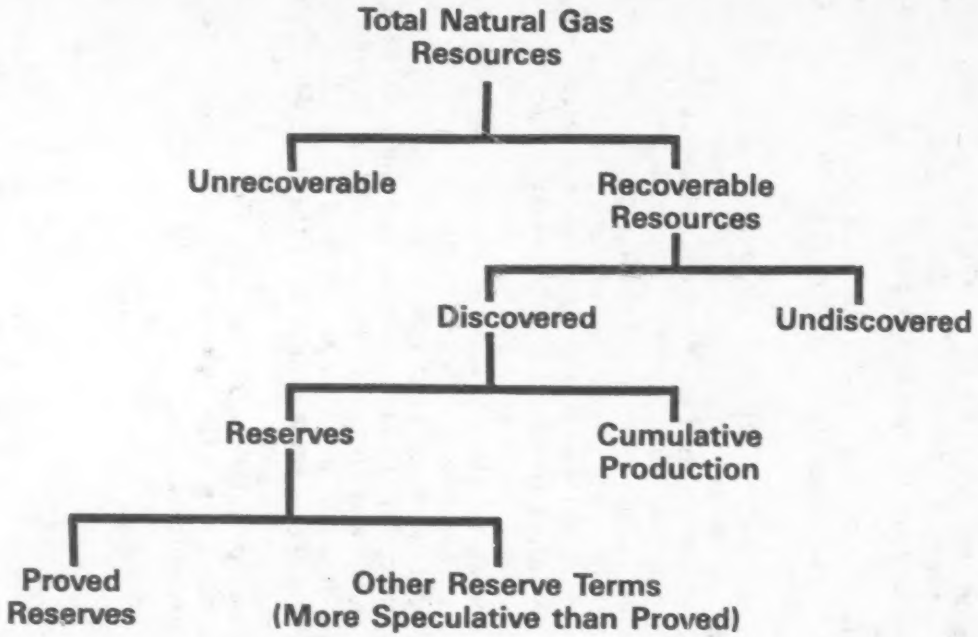

Total Natural Gas Resources
Unrecoverable
Recoverable Resources
Discovered
Undiscovered
Reserves
Cumulative Production
Proved Reserves
Other Reserve Terms (More Speculative than Proved)

CHART 1

Mr. **Evered**. The first source of confusion is often the misunderstanding of the difference between reserves and the more generalized concept of resources. A second is a lack of understanding of the definitions which describe the various kinds of reserves.

The total resource of gas is the amount which was formed and trapped within the Earth. A portion of this total resource is not recoverable by current or foreseeable technology.

Total recoverable resources include both discovered and undiscovered resources. Discovered, recoverable resources consist of two major parts: cumulative production, and reserves.

Cumulative production is the sum of all production to a given date. Reserves, in the broadest context, are those volumes estimated to exist in identified deposits and which are believed to be recoverable in the future with present or anticipated technology.

Proved reserves, on the other hand, are those estimated quantitites which geological and engineering data demonstrate with reasonable certainty to be recoverable in the future under existing economic and operating conditions.

Estimates of proved reserves, and other reserve types as well, are dynamic over time, and are influenced by the amount, the kind, and the quality of data which are available.

Undiscovered recoverable resources are those estimated quantities of gas which are not yet discovered, but are thought to exist in favorable geologic settings.

I'd like to turn now to a brief discussion of the current natural gas reserves and resources of the U.S. lower 48 States, Alaska, Canada, and Mexico.

Estimated lower 48 States proved gas reserves have been generally declining since 1967, as chart 2 shows.

Lower-48 States
Total Proved Reserves of Dry Natural Gas

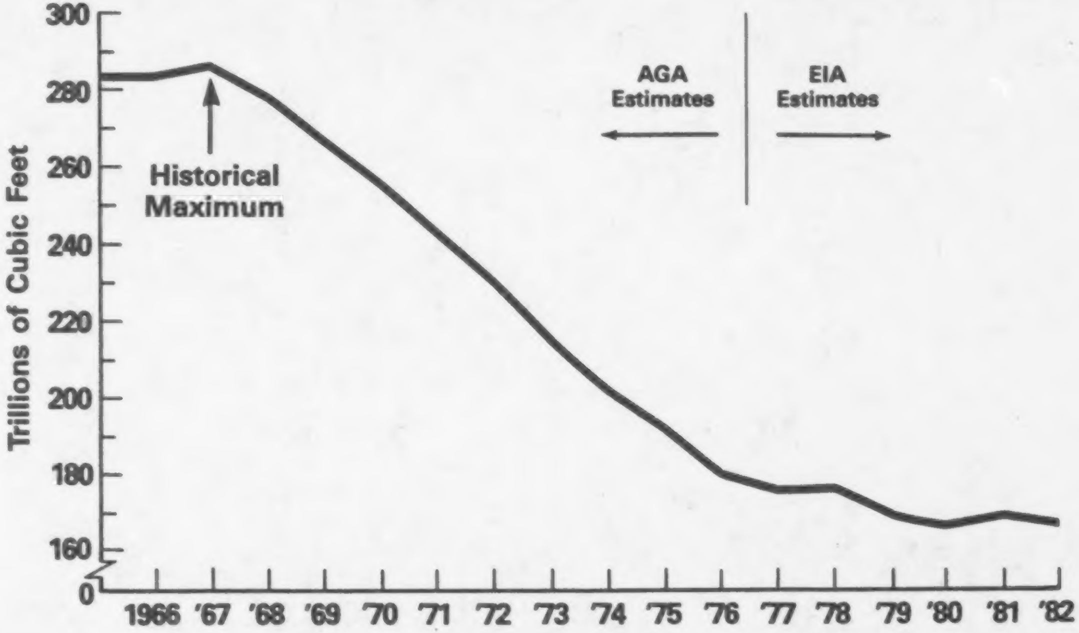


Chart 2

The rate of the decline has slowed somewhat since about 1976. Reserves for the lower 48 stood at 167 trillion cubic feet, or Tcf, at the end of 1982. The data shown on the chart are taken from Energy Information Administration estimates for 1977 through 1982, and from estimates of the American Gas Association for years 1965 through 1976. EIA did not make estimates for years prior to 1977.

Chart 3 shows a plot of annual lower 48 States' gas production and net additions to reserves for the same period.

Lower-48 States

Total Dry Gas Production vs. Net Reserve Additions

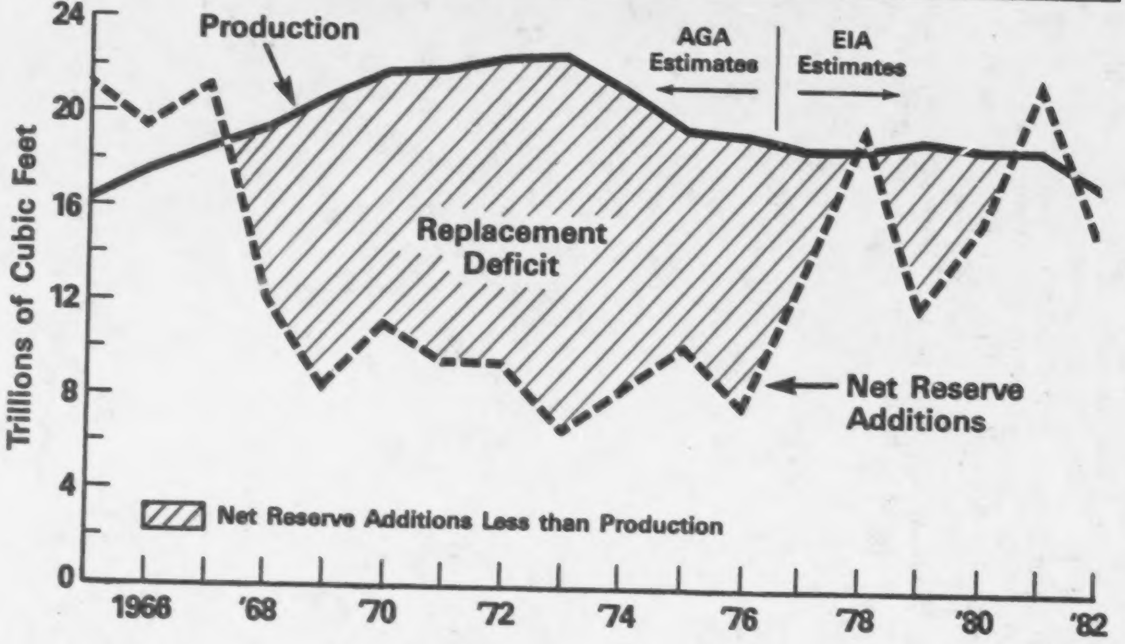


Chart 3

These data illustrate that over the long-term, net additions to new gas supply are not keeping pace with the quantities produced. This shortfall is labeled on chart 3 as Replacement Deficit, and is shaded.

The decline in proved reserves has slowed in response to price incentives, but still only about 84 percent of the quantities produced from 1977 through 1982 were replaced with new gas supply increments in the lower 48.

These trends give me concern about longer term supply adequacy. This concern is heightened by our dependence on gas supply areas which are replacing even smaller fractions of gas produced than is the case for the whole of the lower 48 States.

For instance, reserves from year-end 1977 to 1982 declined by over 9 percent in the combined major producing areas of onshore Texas, onshore Louisiana, the Gulf of Mexico offshore, Oklahoma, New Mexico, Wyoming, and Kansas.

That decline of over 9 percent compares to a decline in reserves for the total lower 48 of 4.9 percent for the same period. At the end of 1982, these areas held about 86 percent of lower 48 reserves and accounted for about 90 percent of production.

Now, let me repeat that point. Major gas-producing areas contributing 90 percent of production showed a proved reserves decline twice as fast as that for the combined 48 States from 1977 through 1982.

Data also show that production is coming from increasingly younger vintages of wells. Gas wells 2 years old or newer produced about 30 percent of the gas in 1975. By 1982, that fraction had increased to 38 percent.

The share of gas produced from wells 5 years old or newer rose from 53 to 65 percent. Furthermore, the data indicate that the number of smaller-size fields found is increasing as a share of total fields discovered.

The U.S. Geological Survey's mean estimate of undiscovered, recoverable natural gas resources in the lower 48 States stands at about 493 Tcf. An additional 172 Tcf of inferred reserves brings the total, in excess of presently proved reserves, to about 665 Tcf.

About 21 percent of that, or 142 Tcf, is expected to lie in the out Continental Shelf and Slope areas. The equivalent Potential Gas Committee estimate is about 742 Tcf, with about 20 percent expected to occur in the offshore, and almost 37 percent expected at depths in excess of 15,000 feet onshore.

USGS and PGC witnesses will present more detail on their estimates of undiscovered, recoverable gas resources, and I defer to them on these matters.

The implications of these estimates are clear. The lower 48 States are endowed with undiscovered, recoverable gas reserves of a very large magnitude, but the maturing nature of our traditional supply areas imparts an urgency to the development of this untapped potential if we're to maintain a continuing adequacy of natural gas supply.

At the end of 1982, Alaska's proved natural gas reserves stood at almost 35 Tcf, amounting to about 17 percent of the Nation's total, or about one-sixth, as the chairman mentioned.

In 1982, Alaska's production was only about 260 billion cubic feet, or about 1½ percent of total U.S. dry gas production.

As you know, the bulk of Alaska's developed gas resources are located in the North Slope area and are not presently connected to markets.

According to available estimates, Alaska also possesses substantial undiscovered gas resources. The USGS mean estimate, plus inferred reserves, is about 107 Tcf. About 84 Tcf, or 63 percent, are expected to be found offshore.

A substantial portion of the offshore resources will have to be discovered under, and produced from beneath, shifting pack ice. The technology for production in this environment has not yet been fully developed.

Alaska's ultimate future as a major gas-producing region would appear to be assured; the presently unanswerable question being, when?

Canada's National Energy Board estimated that that country's marketable reserves at the end of 1982 were about 94 Tcf. Production in Canada in 1983 was approximately 2.3 Tcf.

Exports of gas to the United States were about 700 billion cubic feet, or about 31 percent of the total. Even so, exports were only about 43 percent of the total volume authorized.

Estimates developed by the Geological Survey of Canada for 1983 indicate that Canada's undiscovered natural gas resources are about 336 Tcf, or about 3½ times current marketable reserve levels.

About 26 percent of this potential lies in the Western Canada Sedimentary Basin; 20 percent in the Beaufort Sea-MacKenzie Delta area; and, about 24 percent and 25 percent in the Arctic Islands and Eastern Canada offshore areas, respectively.

Natural gas reserves in the Republic of Mexico were estimated by Petroleos Mexicanos, or Pemex, at 75 Tcf at year-end 1981.

A substantial portion of these reserves, however, are attributed to remote, undeveloped areas, and will require thousands of yet-undrilled wells to develop. It would appear then that some substantial but unknown fraction of Mexico's presently reported reserves do not meet the definitional standards applied in the United States and Canada for proved reserves.

Mexico's marketed production in 1981 was about one and one-half Tcf. Ten to fifteen percent of Mexico's production was flared because gathering and transportation systems were not in place.

The USGS estimates that about 180 Tcf of undiscovered, recoverable gas remains to be found. Mexico's proved and undiscovered resources are thus substantial, constituting about 15 percent of North America's total.

Summary

North American Natural Gas Reserves and Resources

(Trillions of Cubic Feet)

	Reserves	Annual Production	Undiscovered Recoverable Resources
U.S. Lower-48	167 (1982)	17.2 (1982)	665 (1980)
Alaska	35 (1982)	0.3 (1982)	107 (1980)
Canada	94 (1982)	2.3 (1983)	336 (1983)
Mexico	75 (1981)	1.5 (1981)	180 (1981)
Total North America	371	21.3	1,288

Chart 4

In summary, chart 4 shows that North America is indeed rich in natural gas resources. The reserves of the lower 48 States, Alaska, Canada, and Mexico together total about 371 Tcf. The combined annual production of gas currently approximates 21 Tcf.

Very large quantities of recoverable, but as-yet undiscovered, resources are thought to exist, and they total about 1300 Tcf for the Continent as a whole.

Given the magnitude of these figures, some may find in them a basis for complacency and neglect for the future of our natural gas supply posture. I do not.

The lower 48 States are beginning to take on the attributes of a mature supply area. These attributes, and our high level of gas requirements need be a problem in the near term only if we choose not to heed the early indications of decline.

The lower 48 States possess an undiscovered natural gas potential about 4 times our present proved reserve level, and 40 or more times larger than recent levels of production.

Broadly based, market-oriented economic incentives need to exist to find and develop the large resources which are available to us in the increasingly difficult deep and offshore areas of the lower 48 States and in Alaska.

The development of the Nation's potentially recoverable, undiscovered resources will require large amounts of capital and technological progress to make them available.

The regulatory price we pay, in terms of delays, added costs and market inflexibility, must be reduced to a minimum.

The complex environmental considerations and challenges inherent to the development of these gas resources must be met in a timely and responsible fashion.

Intensive research and development needs to be undertaken to work toward the movement of large quantities of uneconomic resources, now generally classified as unconventional, to the proved reserves category.

Much of this work is underway, but much more needs to be done to assure domestic supply adequacy.

Given a resolve to maintain adequate domestic gas supply, we can maintain the posture we now hold for many years to come. I'm optimistic about the continued development of our Nation's natural gas resources if we can move in the directions that I have indicated in a timely manner.

I'd be happy to respond to any questions that the chairman or the subcommittee may have.

[The prepared statement of Mr. Evered follows:]

Statement of the Honorable J. Erich Evered
Administrator, Energy Information Administration
Department of Energy

Mr. Chairman, members of the Subcommittee, I am pleased to appear before you today to provide an overview of the natural gas reserves and resources of North America.

BACKGROUND

The Energy Information Administration (EIA) is an integral, yet independent, agency within the Department of Energy (DOE). As the Government's primary source of energy statistics, its mission is to develop and maintain a credible and consistent base of energy data. These data are provided to the Executive Branch, Congress, state and local governments, industry, and the general public, in order that those who make decisions about energy have accurate, timely and objective information on America's energy position. EIA, by statute, collects and analyzes energy data independent of the DOE's policy and regulatory functions. This is to ensure that the information we provide is politically neutral and unbiased.

Mr. Chairman, I appear before the Subcommittee not only as the head of the Energy Information Administration, but also as a professional petroleum engineer and geologist the bulk of whose career has been devoted to technologies and issues related to natural gas. I will restrict my testimony today to the already-broad topic of natural gas reserves and resources. For a discussion of recent gas market developments, I refer the Subcommittee to my testimony of April 5, 1984 before the Senate Committee on Small Business, Subcommittee on Small Business:Family Farms. Substantial additional information is also contained in "Competition and Other Current Issues in the Natural Gas Market", a report prepared by EIA at the request of the Honorable John Dingell, Chairman of the House Committee on Energy and Commerce. Copies of these two items are provided for use by the Subcommittee along with this testimony.

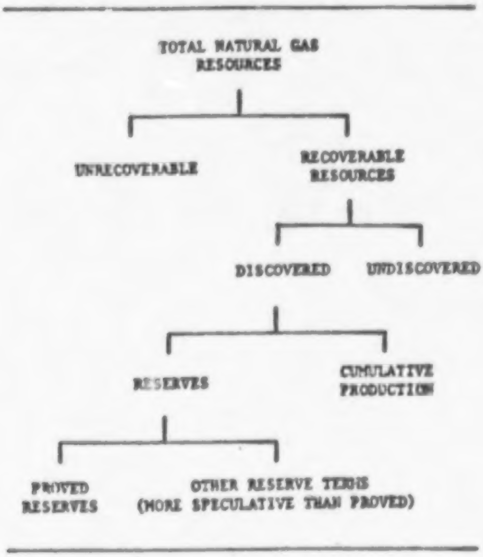
Reserve and Resource Concepts

The adequacy of domestic and world energy supplies has been a matter of public and private concern for many years. However, because universally accepted standard definitions have not been developed, it is not surprising that a great deal of confusion still surrounds the use and understanding of data which are developed to describe these quantities.

The first source of confusion is a misunderstanding of the difference between reserves and the more generalized concept of resources. The second is a lack of understanding of the definitions which describe various kinds of reserves.

The following Figure illustrates the overall relationship of natural gas reserve and resource terms.

RELATIONSHIP OF NATURAL GAS
RESERVE AND RESOURCE TERMS


TOTAL NATURAL GAS RESOURCES
UNRECOVERABLE
RECOVERABLE RESOURCES
DISCOVERED
UNDISCOVERED
RESERVES
CUMULATIVE PRODUCTION
PROVED RESERVES
OTHER RESERVE TERMS (MORE SPECULATIVE THAN PROVED)

The total resource of gas, that is, the amount which existed prior to any production, consists of the total volume which was formed and trapped within the earth. A portion of this total resource is not recoverable by current or foreseeable technology, for two principal reasons. First, much of this portion is dispersed at very low concentrations throughout the earth's crust and cannot be economically extracted. Second, an additional portion of the total resource volume cannot be recovered because available production technology cannot extract all of the in-place gas even when it is present in commercial concentrations. This technical inability to recover 100 percent of the in-place hydrocarbons in a producible deposit may be due to prohibitive economics, intractable physical forces, or a combination of both. While recovery factors for natural gas are much higher than for crude oil, they still do not reach 100 percent. The concept of recoverable resources excludes these unrecoverable fractions of the total resource. As the economics of recovery change, the recoverable portion of the resource will also change.

The total recoverable resource includes both discovered and undiscovered recoverable resources. Discovered recoverable resources consist of two major parts: cumulative production and reserves. Cumulative production is just that—the sum of all production to a given date. Reserves, in the broader context, are those volumes estimated to exist in known deposits, and which are believed to be recoverable in the future through the application of present or anticipated technology. There are numerous categories of reserves that are, by definition, more speculative and less precise than proved reserves. Proved reserves are those quantities of gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in the future under existing economic and operating conditions. Undiscovered recoverable resources are those quantities of gas which are as yet not discovered but which are thought to exist in favorable geologic settings.

When a newly drilled exploratory well encounters oil or gas, an estimate of the volume of proved reserves discovered can be made. This estimate is based upon the initial flow data and rates, thickness of the reservoir encountered, its apparent areal extent, and electrical and other measurements taken inside the hole which provide information about reservoir rock porosity (void space), permeability (ability to conduct fluid flow), fluid saturations, pressures, and temperatures. At this point, the estimate of proved reserves is based on the limited amount of data available from the single well and is only a preliminary judgment as to the amount of economically recoverable oil and gas which has been found.

As more wells are drilled and placed on production, additional reservoir performance data become available. These additional wells also provide more information on the thickness, extent, and other properties of the reservoir. The proved reserves estimate is then revised upward or downward, as appropriate, to reflect these additional data as well as any changes in economic or operating conditions. Changes to the originally estimated proved reserves of a field are usually made over time as revision increases, revision decreases, extensions, or new reservoir discoveries.

Thus, the estimate of proved reserves for any given deposit is dynamic over time and is influenced directly by the amount, kind, and quality of data which become available concerning the deposit. As a general rule, the more data that are available, and the longer the production history, the more accurate the proved reserve estimate becomes. The exact amount of economically producible oil or gas is not known with certainty until the field is permanently abandoned and the recoverable oil or gas has been measured as past production.

It must also be understood that differences among proved reserve figures can occur even when estimators have access to the same data. This is because proved reserves are estimates of quantities which are not subject to direct measurement. Reserve estimates are dependent upon certain subjective interpretations of the individual estimator with regard to the many complex interrelationships of physical and economic factors. Because of these factors, the estimates of equally competent professionals often vary. It is not possible to establish limits on the range of variance between estimates because of the wide variation of complexity encountered in different estimation situations.

Variations in proved reserve estimates in the range of 15 percent, however, are not uncommon. Estimates of undiscovered recoverable resources, due to their speculative nature, can and often do vary broadly.

A more detailed discussion of the occurrence of oil and gas, and the economics of their exploration, is provided in the feature article of the November 1983 issue of EIA's *Monthly Energy Review*, titled "Exploring for Oil and Gas." A copy of the article is provided with this testimony.

The Role of Economics and Technology in Reserve and Resource Estimates

As stated earlier, proved reserves are those quantities of gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in the future under existing economic and operating conditions. In this context, it is seen that the economic viability of available production technology is the determinant factor as to whether or not resources are considered recoverable. Large quantities of gas resources occur in tight geologic formations, in association with coal beds, dissolved in geopressured brine, and, under certain conditions, as icy, slush-like hydrates. The presence of such resources is well established. They are largely excluded, however, from recoverable resources because they are generally not economically exploitable with present technologies.

Proved reserve estimates include only those resources which are economically producible with present-day technology. Present proved reserve estimates include some gas from tight formations and from coal beds where economic viability has been established. The largest fraction however, is excluded from present reserve and resource estimates as presently uneconomical and unrecoverable. There is a continuum from conventional resources to those that are unconventional — that is especially the case with gas in tight formations — and as technology advances and economics change, the dividing line shifts between what is economic and what is not. Essentially all geopressured brine and hydrate resources are considered to be presently subeconomic. If advances in technology and improvements in economics permit, these resources will gradually become a portion of those resources classified as recoverable.

Production Characteristics of Natural Gas

The preponderance of presently exploitable natural gas resources occurs as one of two types: nonassociated gas or associated-dissolved gas. Nonassociated gas is that which exists in geologic reservoirs alone and not in conjunction with significant quantities of crude oil.

Associated-dissolved gas occurs in crude oil bearing reservoirs as free gas (associated), as dissolved gas (in solution with oil), or as both.

All oil and/or gas reservoirs are subject to certain natural forces and characteristics that determine how they will behave when volumes of gas and/or oil are removed from them. In some formations, the pore spaces which contain the hydrocarbons are not effectively connected to adjacent underground waters. In this instance, the withdrawal of hydrocarbons via production results in behavior akin to that which one would see if such withdrawal were from a closed container. As fluids are produced, the naturally occurring underground pressure declines, with the decline related to the cumulative quantities withdrawn. Reservoirs of this kind are generally referred to as depletion-type reservoirs.

The second major type of reservoir is that in which the hydrocarbon-containing pore spaces are effectively connected (to one degree or another) to adjacent underground waters, usually brine waters. Because of this connection, the pressure within the producing reservoir is influenced by the influx of water as it replaces produced fluids. Depending on the degree of communication with the water, and the natural pressures available, pressure declines can range from little, or none, to those close to that which would be observed in a strictly depletion-type situation.

Other physical factors also influence the relationship of flow rate to the natural pressure differentials available to initiate and sustain production. These include permeability (a measure of the ease with which fluids can move within the geologic formation or reservoir), hydrocarbon viscosity, and the characteristics of the producing facilities installed. When a reservoir contains significant amounts of crude oil, the production of gas is normally a function of the quantity of oil produced, with oil production determining the quantity and timing of gas availability.

The point I would make is that natural, physical forces play a major part in determining the rates at which natural gas can be produced from the proved reserve inventory. Important roles are also played by economics, conservation practices, and environmental considerations, but the quantities of producible gas available to meet market needs at any given time are heavily influenced by forces which lie outside the discretionary control of planners or regulators.

North American Perspective

North America can be accurately characterized as the cradle of the modern petroleum industry. Of course, petroleum was utilized for a variety of limited purposes in portions of the world even in pre-Biblical times. By the mid-nineteenth century, whale oil had become scarce and chemists had discovered that the distillation of crude oil from natural seepages was an excellent substitute. Some would say that the modern petroleum era in North America was ushered in by the completion of the Drake well in Pennsylvania in 1859.

Others would mark its beginning with the development of the Spindletop field near Beaumont, Texas in 1901. In any event, two world wars brought the North American oil industry to a rather extensive level of development by the early 1940's.

Natural gas lagged behind oil in its development and did not expand significantly until the mid-1940's and the advent of the transcontinental gas transportation systems. Annual production of natural gas in the United States did not exceed 5 trillion cubic feet (Tcf) until 1947 but doubled to 10 Tcf by 1955. By 1981, North American gross natural gas production reached approximately 26.6 Tcf, with the United States providing about 81 percent of the total. Canada contributed about 13 percent of the total in that year and Mexico about six percent. North America's total gross natural gas production constituted about 41 percent of the world's total. Current estimates of proved natural gas reserves in North America stand at approximately 371 Tcf, or about 12 percent of the world total.

The Energy Information Administration's Role in Data Development

Accurate and regularly updated estimates of the Nation's proved reserves of crude oil, natural gas, and natural gas liquids are essential to the development, implementation, and evaluation of energy policy and legislation. In the past, the Government and the public relied principally upon estimates prepared by the American Petroleum Institute (API) and the American Gas Association (AGA).

In the early 1970's, the Federal Power Commission (FPC), the Federal Energy Administration (FEA), and others separately established programs to collect data on, verify, or independently estimate domestic proved reserves of natural gas or crude oil. Some of these programs were one-time efforts; others were repeated. Each was narrowly defined to meet the particular needs of the sponsoring agency. The programs overlapped to some extent and, taken together, did not establish a unified, verifiable, comprehensive, and continuing statistical series.

In response to the recognized need for such data and to eliminate duplication, the EIA developed a program to estimate U.S. proved reserves of crude oil, natural gas, and natural gas liquids. The EIA's estimates are based on data filed by operators of oil and gas wells on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," and by operators of natural gas processing plants on Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production." Reports for years ending December 31 have been published for 1977 through 1982. We are presently in the midst of preparing the report for calendar year 1983 and expect to complete it in the late summer. A copy of EIA's

1982 Annual Oil and Gas Reserves Report is provided with my testimony.

After EIA's program to develop proved reserves statistics was underway, API and AGA each chose to cease publishing comprehensive annual estimates. Their last reports were published for 1979. EIA's reserve estimation program is currently the only continuing, comprehensive domestic oil and gas reserve estimation effort underway.

The EIA reserves program was designed in close cooperation with industry to be as consistent as possible with that of the API and the AGA. However, it should be noted that the API/AGA and EIA estimates differ as to methods of preparation and detailed content. The overlap between the precedent, private systems and the EIA program for the years 1977, 1978, and 1979 was intentional, so that any important differences could be identified and analyzed.

The data generation methods used in preparing the EIA estimates differ markedly from those used by the API and AGA. The EIA estimates are based on data filed by more than 2,500 operators of oil and gas wells on Form EIA-23 and by the operators of more than 1000 natural gas processing plants. The operators reporting on Form EIA-23 have available to them all of the existing information — usually proprietary — concerning the reserves associated with their properties.

EIA's reserves program also includes an independent field validation effort. EIA staff members visit a sample of respondents who have submitted information and review their filings. This staff of professional engineers and geologists also make their own independent estimates of the reserves of selected oil and gas fields, based upon all of the data available to the operator, to determine the technical reasonableness of the estimate filed. The EIA's independent reviews have indicated that the estimates submitted by respondents have been of professional quality.

The EIA's role in the development of undiscovered resource data for the United States is limited. This function is the responsibility of the United States Geological Survey (USGS) which, I understand, will present testimony on this subject to the Subcommittee. The EIA does, however, cooperate in every way possible to assist the USGS in the discharge of their tasks. This cooperation has included making detailed data from our proved reserve estimation program available to them for their purposes and use. In this connection, I should mention the proprietary and confidential nature of much of the company-specific data which we collect. EIA has developed a comprehensive confidentiality policy in this regard which safeguards such data from disclosure when it is shared with agencies, such as the USGS, who have a lawful need-to-know.

Another significant activity in the area of undiscovered natural gas resource appraisal for the United States is carried out by the Potential Gas Committee (PGC). This committee is comprised of volunteer members from the natural gas industry, government agencies, and academic institutions who are concerned with natural gas resources. This Committee functions independently but with the guidance and assistance of the Potential Gas Agency of the Colorado School of Mines and it is supported by the AGA. Several members of my technical staff serve as observers and EIA representatives to this group. I understand that a representative of the PGC will also be presenting testimony to the Subcommittee.

The EIA does have a limited Foreign Energy Supply Assessment Program (FESAP) which gathers reserve and resource data on significant oil and gas producing areas of the world. This effort is limited, however, by our lack of authority to collect data from foreign entities, and by the press of higher priority work. For the most part, our FESAP efforts have focused on crude oil. One such report, which may be of interest to the Subcommittee, is our recent report on The Petroleum Resources of Mexico. A copy of this report is provided with my testimony for your use. The USGS cooperates with us in the preparation of these reports in that they provide the information included on undiscovered, recoverable resources.

In the sections that follow, my testimony presents a general overview of the current natural gas reserves and resources status for the U.S. Lower-48 States, Alaska, Canada, and Mexico. Following the written portion of my testimony are three Tables which summarize salient EIA data on reserve trends in the Lower-48 States.

U.S. LOWER-48 STATES

Proved Reserves

Estimates of year-end proved natural gas reserves have been made by EIA for the six-year period from 1977 through 1982. As mentioned earlier, our estimates for 1983 will be available later this year. The estimates of proved dry natural gas reserves for the Lower-48 States are summarized for this period in Table 1. Reserves fell from about 175.2 Tcf at the end of 1977 to just over 166.5 Tcf at year-end 1982. This decline of approximately 8.6 Tcf (4.9 percent) was rather modest and would seem to indicate a period of relative stability in Lower-48 States reserve levels.

Table 2 shows these same year-end reserve values but additionally summarizes the various components of reserve change for each year. The column labeled Total Discoveries is the sum of the columns labeled Extensions, New Field Discoveries, and New Reservoir Discoveries. Total discoveries represent a measure of the newly found increments of gas supply for a given year. Cumulative production during the period was about 110.5 Tcf and so it can be seen that new gas supply increments replaced about 84 percent of the resource withdrawn via production. I would also note that production exceeded total discoveries in each of the six years. As mentioned earlier, reserve estimates are dynamic and subject to revision as more data are obtained. This component of change (revisions) is included in the column designated Net of Corrections, Adjustments, and Revisions along with certain statistical adjustments which are required by the statistical design of the survey, and corrections of respondent reported data. The net of these changes, when added to Total Discoveries, is posted in the column labeled Net Reserve Additions. Since the cumulative Net of Corrections, Adjustments, and Revisions was +3.4 Tcf for the period, cumulative Net Reserve Additions exceeded accumulated Total Discoveries by that same amount. Thus, on an overall basis, Net Reserve Additions replaced about 96.2 Tcf (87 percent) of the 110.5 Tcf produced from 1977 through 1982.

The graphs on the lower portion of Table 2 chart the reserve and reserve change elements tabulated in the upper section of the table. The right hand graph also plots the annual ratio of year-end proved reserves divided by production (R/P) in that year. This ratio is used by many analysts as an indicator of the robustness of gas supply for a given area. It must be remembered, however, that, for a given reserve level, the R/P ratio will move in the opposite direction from production. The reduced production levels of 1982 thus moved the R/P upward from 9.1, at the end of 1981, to 9.7 in 1982 indicating a significant but somewhat illusory upward trend in the R/P ratio. If production in 1982 had remained at the 1981 level of 18.5 Tcf, the R/P ratio would not have gone up but instead would have declined to about 8.9.

Much of the natural gas production in the Lower-48 States flows from a relatively few major producing areas. Some of these areas, for instance Texas Onshore, the Gulf of Mexico Offshore, and Louisiana Onshore, have not replaced the quantities of natural gas produced with new discoveries and are reaching a stage of apparent maturity. Reserve data for a group of major producing areas is aggregated in Table 3. This group is comprised of onshore Texas, the offshore Gulf of Mexico, Oklahoma, onshore Louisiana, New Mexico, Wyoming, and Kansas. In 1982, these areas, combined, held about 86 percent of Lower-48 States reserves and accounted for approximately 90 percent of the production. Between year-end 1977 and year-end 1982, proved reserves in these areas fell by about 14.3 Tcf (9.1 percent). This compares to a decline of 8.6 Tcf (4.9 percent) for the Lower-48 States as a whole. As was the case for the Total Lower-48 States, the 1982 R/P ratio moved deceptively upward. If the demand for gas in 1982 had remained at the 1981 level, the R/P ratio would have fallen to about 8.5 for these areas. On an overall basis, Net Reserve Additions replaced only about 80 percent of production in the major areas as opposed to 87 percent for the total Lower-48 States.

These reserve trends lead me to conclude that we are beginning to see a maturation of currently developed natural gas resources in the Lower-48 States which will require increasingly vigorous exploration efforts to maintain supply adequacy. As our developed natural gas resource base matures, we become more dependent on production increments from newer vintage wells. We see this phenomenon reflected in the data which relates gas production to producing wells by age of well. Statistics from Dwight's Energydata show that, in 1975, approximately 53 percent of gas production came from wells which were five years old or younger. By 1982, this fraction had increased to about 65 percent. For gas wells two years old or newer, the gas production share increased from 30 percent in 1975 to 38 percent in 1982.

Given a finite resource base, the tendency is to find the larger targets earlier in the exploration cycle. As that cycle progresses, the average size of the deposits remaining to be discovered tends to decrease. The American Association of Petroleum Geologists (AAPG) develops data on the number of new gas fields proved, after six years, to be of significant size. This lag of six years between the initial discovery of a field and its classification into various field size categories allows for the sufficient passage of time to learn about that field's likely ultimate size. The AAPG data show that, of the new fields drilled in 1970, 79 were classified as containing less than 6 billion cubic feet (Bcf). In 1975, the number of new fields found in that size class had risen to 336. In 1976, the latest year for which the appropriately lagged data are available, the number was 443. The number of new fields in the less-than-6 Bcf category thus rose from about 60 percent of the total number of all fields classified in 1970 to 83 percent and 87 percent in 1975 and 1976, respectively.

Undiscovered, Recoverable Natural Gas Resources

I will leave the extensive discussion of the estimates of undiscovered recoverable natural gas resources to the expert witnesses who are scheduled to appear before you on this subject. I do want to comment briefly, however, on their estimates.

The USGS mean estimate of undiscovered recoverable natural gas resources in the Lower-48 States stands at about 493 Tcf. An additional 172 Tcf of inferred reserves brings the total, in excess of presently proved reserves, to about 665 Tcf. About 21 percent of that (142 Tcf) is expected to lie in the outer continental shelf and slope areas.

The essentially equivalent PGC estimate for the Lower-48 States is about 742 Tcf, with about 20 percent (149 Tcf) estimated as expected to occur in the offshore. About 274 Tcf are expected to be found at depths between 15,000 and 30,000 feet onshore.

Given the fact that precise estimates of these quantities are impossible to achieve, likely estimates for the Lower-48 States total range between 665 and 742 Tcf. Perhaps most importantly, though, the quantities which lie in the more difficult and expensive offshore and/or deep areas range up to 423 Tcf, or to about 57 percent of the higher total estimate.

The implications of these estimates are clear. The Lower-48 States are endowed with undiscovered, recoverable natural gas resources of a very large magnitude, ranging up to nearly four and one-half times the current level of proved reserves. This amount could be increased substantially if the technology can be developed to tap the presently uneconomic gas resources such as gas in tight formations, coal bed methane, and geopressured brines. Much of the presently recoverable undeveloped resource (perhaps more than one-half) lies in areas which will be technically difficult, costly, and environmentally challenging to develop. The maturing nature of our traditional Lower-48 States gas supply areas imparts an urgency to the development of our untapped potential, if we are to maintain a continuing adequacy of natural gas supply. The smooth and timely development of this potential will require appropriate market-oriented incentives, the removal of regulatory impediments, and the resolution of significant technical and environmental challenges if we are to be successful.

Further information on this subject is contained in "The Impact of Federal Actions on Petroleum Exploration", featured in the December 1983(2) Monthly Energy Review. A copy of the article is incorporated with this testimony.

Lower-48 States North American Gas Imports

Imports of natural gas from Canada began in the early 1950's. These have been, for the most part, pipeline deliveries, although minor quantities were transported by truck in the form of liquified natural gas (LNG) during the

1970's. The volume imported grew rapidly and steadily from about 11 Bcf per year in 1955 to a peak of 1,027 Bcf in 1973. Between 1973 and 1979, the volumes imported ranged roughly between 880 Bcf and 1,000 Bcf. Since 1979, volumes have moved rather narrowly between 700 Bcf and 800 Bcf per year. Imports in 1983 were about 712 Bcf, at an average price of $4.49 per Mcf.

About 83 percent of all Canadian imports enter the United States through Idaho, Minnesota, and Montana, primarily serving West Coast and Midwestern markets. Smaller markets are also served in the Eastern United States, including New York and Vermont, but these markets comprise less than 5 percent of the total. Canadian imports are an important but relatively small fraction of Lower-48 States consumption, constituting about 4.4 percent of total gas consumption in 1982. In that same year, Canadian imports amounted to about 84 percent of all natural gas imported into the United States.

Imports from Mexico began in 1952, reaching about 50 Bcf annually in the mid-sixties. Mexican gas imports tapered off rather sharply in the 1970's and were actually zero for four years during that period. In 1980, imported volumes rebounded and surpassed the 100 Bcf mark. Imports in 1983 were about 75 Bcf, at an average price of $4.70 per Mcf.

All Mexican imports enter the United States at Hidalgo, Texas and are purchased by Border Gas Inc., an interstate pipeline company. In 1982, imports from Mexico constituted less than one-half of one percent of total U.S. gas consumption.

Lower-48 States Exports

Exports of gas from the Lower-48 States have always been very small. Exports to Canada reached their peak in 1968 when a total of just under 82 Bcf were shipped. Exports to Canadian consumers in 1983 were miniscule, totalling less than 1 Bcf at an average price of $4.60 per Mcf.

Exports to Mexico have declined almost from their beginning. The peak level occurred in 1955 when nearly 20 Bcf were exported. Exports in 1983 totalled less than 2 Bcf at an average price of $4.78 per Mcf.

A copy of the article titled "U.S. Imports and Exports of Natural Gas - 1982," may be of interest to the Subcommittee and is included with my testimony. This article appeared in EIA's July 1983 Natural Gas Monthly.

ALASKA

Proved Reserves

Due in large measure to its remoteness from natural gas consuming centers, Alaskan hydrocarbon exploration has been almost exclusively targeted toward the discovery of crude oil. But the inherent imprecision of exploration targeting, particularly in a such a little-explored region, coupled with the fact that much of Alaska's natural gas occurs in association with crude oil, has nevertheless resulted in the discovery of significant gas reserves.

There have been five distinct periods of Alaskan exploratory activity subsequent to the initial Russian reports of oil seepages in 1853. The first, from 1898 to 1906, involved shallow onshore drilling in the Cook Inlet region and southward along the Pacific Coast. This activity resulted in the discovery of Alaska's first petroleum field, Katalla at Controller Bay south of Valdez. This short-lived initial exploratory activity peaked in 1904 and ended in 1906 when all Alaskan petroleum lands were withdrawn from exploration as a result of the Taft Administration's Pinchot-Ballinger controversy over conservation of Alaska's public domain.

The second exploratory period was initiated by passage of the Mineral Leasing Act of 1920. This period extended through the 1930's and resulted in the discovery of the first Cook Inlet field. Exploration during this second period was not very successful, primarily because it was too shallowly targeted.

A third period of exploratory activity began in 1944 with the Federal government's undertaking of exploration in the Naval Petroleum Reserve Number Three, located on the North Slope of the Brooks Range. This activity continues, with only modest success, right up to the present.

The fourth period of activity took place from the mid-1950's through the 1960's and centered in the Cook Inlet area. The Swanson River Unit No. 1, the first deep test in the Cook Inlet Basin, was drilled in 1957 and resulted in the discovery of a major oil field. Between 1957 and the end of 1965, five major oil fields, one rich gas condensate field, and ten dry gas fields were discovered, containing about 500 million barrels of crude oil reserves and 3 trillion cubic feet of natural gas reserves.

The fifth period of activity centers on the North Slope, east of Naval Petroleum Reserve Number Three, and put Alaska on the world's petroleum map. It began with drilling of the Prudhoe Bay State No. 1 well in the winter of 1967-1968, resulting in discovery of the supergiant Prudhoe Bay Field. The gas reserves of this field alone, which were booked in 1970, were an order of magnitude larger than the total of everything that had been found in Alaska up to that time.

The exploration of those portions of the remainder of the North Slope and its contiguous Beaufort Sea shelf that are open to development continues actively at present. At the end of 1982, Alaska's proved dry natural gas reserves stood at 34.9 Tcf, amounting to 17.4 percent of the Nation's total proved gas reserves. Twelve percent of these reserves are nonassociated gas, and the remaining 88 percent are associated-dissolved gas. The principle change to Alaskan proved gas reserves since the booking of Prudhoe Bay Field has been a significant increase resulting from net positive revisions to estimates of the reserves of the known fields. Between the end of 1978 and the end of 1982, these amounted to 3.77 Tcf compared to an increase from new discoveries of only 0.34 Tcf in the same period. Most of these revisions are due to increased knowledge of Prudhoe Bay Field itself.

By contrast, Alaska's marketed gas production in 1982 was only about 260 Bcf. This was 0.8 percent of its proved reserves and only 1.5 percent of total U.S. production. Some 72 percent of the production came from nonassociated natural gas reservoirs, for the most part located in the Cook Inlet region. Only 28 percent came from associated-dissolved natural gas reservoirs. Most of the production was used locally in production operations, for residential and commercial purposes, or was liquefied for export via tanker to Japan. In 1983, exports to Japan totaled about 53 Bcf at an average price of $5.11 per Mcf.

There are no large indigenous markets for Alaskan gas. Most of the associated-dissolved gas produced during North Slope crude oil production operations is being reinjected as part of pressure maintenance programs (91 percent of 1983's gross withdrawals). These volumes are not included in the above production figures.

While the recent Alaskan proved reserves trend might give the impression that exploration has met with little success on the North Slope following the Prudhoe Bay discovery, that impression would be inaccurate. A number of accumulations of either crude oil or condensate, in association with natural gas, have been discovered over the past 15 years. Virtually any one of these would have been hailed as a major discovery had it been located in the Lower-48 States, either onshore or offshore. Most of these are located in the vicinity of Prudhoe Bay. Whether they will contain proved reserves of gas or merely constitute recoverable resources whose location is now better known than most, is entirely dependent upon whether their crude oil or condensate can be commercially produced. Due to the hostile environment of the North Slope and the numerous holes that are required for adequate evaluation, commercial viability is not as swiftly determined as it is in more hospitable places.

A major North Slope oil field which has attained commercial status is the Kuparuk River Field, discovered in 1969 and booked in 1978. This field is conveniently located near the Trans Alaska Pipeline System (TAPS) terminal at Prudhoe Bay. Production from it began in December 1981. An important point is that had the TAPS line not already been in place to service Prudhoe Bay, the Kuparuk River Field, although a giant by North American standards, would probably have been noncommercial on its own merits.

There are a number of identified "candidate" accumulations that hold promise for adding significantly to the proved gas reserves of the North Slope, but all are currently being evaluated for commercial potential. Prominent among them are: Milne Point, discovered in 1980; the Endicott reservoir underlying the Sag Delta-Duck Island area (which may be a giant field); the Gwydyr Bay discovery; and discoveries at Seal Island and in the Point Thompson-Flaxman Island area. The latter might hold up to 5 Tcf of recoverable natural gas if it proves to be commercial.

Alaskan Natural Gas Transportation Proposals

The effort to bring North Slope gas to Lower-48 States markets began in 1974, six years after the Prudhoe Bay discovery. In March of that year the Arctic Gas pipeline, which would have carried gas eastward along the North Slope and then southeast through Canada to United States Midwestern markets, was proposed. September of that year saw a proposal by El Paso Alaska to pipe the gas southward along the TAPS route for liquefaction at the terminus and shipment to the West Coast via tanker. Finally, in July 1976, the Alcan line was proposed. It would follow the TAPS line route to the Alaskan Highway south of the Brooks Range, and then follow the highway to the Canadian border. Thereafter, it would pass southeastward across the provinces of Alberta and Saskatchewan to the U.S. border at Idaho. There it would break into an eastern leg terminating in Illinois and a western leg terminating in California.

In May 1977, a Federal Power Commission administrative law judge, after extensive hearings, split a decision between the Alcan and Arctic Gas proposals. Canada's National Energy Board rejected the Arctic Gas proposal and essentially accepted the Alcan proposal. In September 1977, the President recommended the Alcan line to the Congress.

Parts of the Alcan project are already in place. Construction of the eastern and western legs was divided into two phases. Phase I of the western leg began transporting Alberta gas to the U.S. in October 1981, and Phase I of the eastern leg began transporting Alberta gas a year later.

Alaskan Undiscovered, Recoverable Natural Gas

At some indeterminate time in the medium-to-long-range future, the reserves behind the proposed transportation systems, as well as those yet to be discovered and proved, will be needed in Lower-48 States markets. And there do indeed appear to be substantial Alaskan gas resources yet to be converted to proved reserves. The United States Geological Survey (USGS), as noted earlier, provides the Federal estimates of undiscovered, recoverable natural gas resources. A side-effect of the USGS decision to separately estimate onshore and offshore resources nationwide is that only a mean estimate representing the expected undiscovered resource volume has been set forth for Alaska as a whole.

As of 1980, the USGS' mean estimate of total Alaskan undiscovered, recoverable gas reserves was about 107 Tcf. This figure includes their estimates of inferred reserves for the region and thus represents estimated quantities in excess of presently proved reserves. This amount approximates one-half of the present total United States proved reserves inventory. Nearly two-thirds of the total estimated undiscovered Alaskan gas resource is believed to occur offshore. A substantial portion of these Offshore resources will have to be discovered under, and produced from beneath, shifting pack ice. The technology for this has not yet been fully developed, although, on the other hand, most of the gas is expected in water depths of less than 650 feet, well within the industry's proven technical capabilities in ice-free waters.

The Potential Gas Committee has estimated the total undiscovered, recoverable natural gas resources for Alaska at 134 Tcf. Of that amount, they also estimate that about two-thirds (84 Tcf) is to be found offshore.

Likely estimates of undiscovered natural gas resources in Alaska thus range between 107 Tcf and 134 Tcf. As was the case for the Lower-48 States, it seems clear that the undiscovered potential is quite large. The challenges to development of Alaska's resources are the same as for the Lower-48 States, although perhaps to greater degrees. Alaska's ultimate future as a major gas producing region would appear to be assured; the presently unanswerable question is that of "when?".

CANADA

Marketable Reserves

The marketable natural gas reserves of Canada have been growing in recent years. In 1975, Canada's National Energy Board (NEB) estimated marketable reserves at just over 59 Tcf. The definitions utilized by Canadian authorities differ slightly from those used in the United States, but these volumes are essentially equivalent in concept to the U.S. proved dry natural gas estimates which I used in my discussion of the Lower-48 States. At the end of 1982, the NEB estimated reserves at 94 Tcf. Some of the growth seen in these figures resulted from the inclusion of the marketable resources of the MacKenzie Delta and Arctic Islands regions, beginning in 1979. Prior to that time, these areas had not been included due to their distance from available transportation facilities. The marketable reserves of these regions should be included in a discussion of Canada's total reserves, however.

About 80 percent of the total reserve (75 Tcf) lies within the western provinces of Alberta and British Columbia. Approximately 18 percent is found in the MacKenzie Delta and Arctic Islands areas.

Softer markets for natural gas have had a generally depressing effect on Canadian drilling, as they have recently in the United States. In 1983 and early 1984, however, significant gas discoveries were made in the Arctic Islands and MacKenzie Delta areas. Drilling in the eastern offshore Sable Island area consisted mostly of delineation work with no significant new finds being reported for that area.

Production in Canada in 1983 was approximately 2.3 Tcf. Exports to the United States were about 700 Bcf, or about 31 percent of the total. Even so, exports to the United States were only about 43 percent of the total volumes authorized. The reduction of U.S. demand and severe price competition in the U.S. marketplace from fuel oil and domestic natural gas, combined to produce this effect. In response to these pressures, the Canadian Government reduced the export price for Canadian gas to $4.40 per million Btu in April of 1983. In July of 1983, a Volume Related Incentive Pricing (VRIP) program was introduced to remain in effect for two years. Under this program, Canadian exporters can sell gas in excess of an established base quantity at reduced prices ($3.40 per million Btu during the first year). The base quantity in most cases is set at 50 percent of the authorized annual volume.

The U.S. Department of Energy issued new guidelines on the importation of gas in February of 1984. The U.S. policy goal is to have a supply of natural gas supplemental to domestic production available on a competitive, market-responsive basis, while avoiding undue dependence on unreliable foreign sources of supply.

The National Energy Board continuously analyzes Canadian reserves, deliverability, and internal requirements in order to establish those volumes of gas which are considered surplus and therefore available for export. Using past NEB calculations as a point of reference, it would appear that Canada's presently authorized export levels are less than one-half of those which might be permitted under their formula.

Included with my testimony is a copy of an article titled "The Canadian Natural Gas Situation - An Overview" that may be of interest to the Subcommittee. This article appeared in the July 1983 issue of EIA's Natural Gas Monthly.

Undiscovered Natural Gas Resources

Estimates developed by the Geological Survey of Canada indicate that Canada's undiscovered natural gas resources are quite large. As with the work done by the USGS in the United States, they employ a probability, or expectation level, in the development of their figures. Their average expectation level for the whole of Canada is approximately 336 Tcf, or about three and one-half times current marketable reserve levels. About 26 percent of this potential lies in the Western Canada Sedimentary Basin, 20 percent in the Beaufort Sea-MacKenzie Delta Area, and about 24 percent and 25 percent in the Arctic Islands and Eastern Canada Offshore areas, respectively. The remainder is distributed more or less evenly between the Canadian west coast and the eastern onshore areas.

As is the case for undiscovered potential in all of the geographic segments of North America, the portion of these resources which may become commercially viable depends on many factors. Prevailing economic conditions and progress in the development of production and transportation technologies will be major determinants. The lead times from discovery to commercial development will also be long, particularly in the more hostile frontier areas where a large portion of the potential lies. For the nearer term, perhaps a decade, Canada's newly found resources will most likely come from its more mature (but also considerably more hospitable) Western Sedimentary Basin.

MEXICO

Reserves

Natural gas reserves in the Republic of Mexico were estimated at 77 Tcf as of year-end 1983. This estimate was made by Pemex, the Mexican government's oil and gas exploitation entity. Mexico's reserves constitute approximately two and one-half percent of total world reserve volumes and contribute a little more than 20 percent to the North American total.

The problems associated with the absence of universally accepted reserve and resource terms were mentioned earlier. These problems are further compounded when discussing the reserves and resources of other countries. It seems rather clear that the precision which we can attach to the estimates of Mexico's estimated reserves is somewhat less than that which can be attributed to estimated reserve quantities in the United States. For instance, a substantial portion of the reported reserves lie in regions that are not developed.

The exploitation of these resources will require the drilling of thousands of wells in remote, mountainous, and/or rain forest environments where operations will be difficult, slow and costly. It would appear then, that some substantial, but unknown, fraction of Mexico's presently reported reserves do not meet the definition of proved reserves utilized in the United States. Furthermore, the process through which these reserves may ultimately be confirmed as "proved" will be a long and costly one.

Reported natural gas reserves in Mexico have remained stable over the past three years, rising from 75 Tcf at year-end 1981, to the 1983 level of 77 Tcf. Petroleos Mexicanos (Pemex) is the Mexican national entity responsible for the development of the Nation's hydrocarbon resources. Pemex's recent emphasis has been directed largely toward exploratory drilling, rather than developmental drilling, and has additionally focused on finding light oil reserves to replace production. These activities have resulted in the addition of some natural gas reserves but probably account for the modest changes of recent years.

Mexico's gross production of natural gas was about 1.5 Tcf in 1981. Quantities which were vented and flared were approximately 17 percent of gross production. Marketed production was about 1.2 Tcf, most of which was utilized for the production of electricity, by residential consumers, and in oil and gas operations. A substantial fraction of the gas flared has been in the offshore oil producing areas where the pipeline systems required to gather the gas have not been available. The Mexican government is moving rapidly to rectify this problem with the installation of pipelines and processing plants.

The outlook for future gas production in Mexico is unclear. Opportunities for the development of substantially increased export volumes will hinge on the rate at which their resources are developed and on economic progress, with perhaps attendant increased internal gas requirements. Recent depressed world crude oil markets have undoubtedly caused a slowdown in the rate of planned economic development. Lower returns from crude oil sales have tended to reduce the capital available for oil and gas development and for needed plant construction. Mexico obviously possesses significant potential for natural gas resource development, but the trajectory of such development is not known.

Additional information of interest to the Subcommittee can be found in "The Mexican Natural Gas Situation - An Overview," featured in the October 1983 issue of the Natural Gas Monthly. A copy is provided with this testimony.

Undiscovered Recoverable Natural Gas Resources

The USGS estimates that about 180 Tcf of undiscovered, recoverable natural gas remain to be found in Mexico. These undiscovered quantities are about two and one-half times current reserve levels. About one-third of this undiscovered potential lies in the Northern portion of the country, with the remaining two-thirds attributable to the more prolific Southeastern region. This figure, in combination with cumulative natural gas production and present reserve levels, indicates that Mexico has identified about 34 percent of its total recoverable natural gas resource.

SUMMARY

North America is indeed rich in natural gas resources. The reserves of the Lower-48 States, Alaska, Canada, and Mexico together total about 371 Tcf. The combined annual production of gas currently approximates 21 Tcf. Very large quantities of recoverable but undiscovered resources are thought to exist and total about 1,288 Tcf for the continent as a whole. Given the magnitude of these figures, some may find in them a basis for complacency and neglect for the future of our natural gas supply posture — I do not.

The Lower-48 States utilize about 83 percent of the continent's total annual natural gas production to fuel our highly skewed share of the continent's economy and provide a standard of living known in few places throughout the world. Its indigenous developed resource is, in my view, beginning to take on the attributes of a mature supply area. We see this in the slowly declining reserve position of its major producing areas, in the ever-increasing dependence upon recently drilled wells to provide larger and larger proportions of annual production, and in the increasing difficulty of finding large gas deposits which are the foundation of our presently developed resource.

The attributes of a maturing supply area and our high level of gas requirements need be a problem in the near term only if we choose not to heed the early indications of difficulty. The Lower-48 States possess an undiscovered natural gas potential about four times our present proved reserve level, and forty or more times larger than recent levels of annual production. Given a resolve to maintain domestic supply adequacy and security, we can maintain the posture we now hold for many years to come.

As I have explained, the pace at which the nation converts its large resource potential to proved reserves is largely a function of economics. Broadly-based, market-oriented economic incentives need to exist to find and develop the large resources which are available to us in the increasingly difficult deep and offshore areas of the Lower-48 States. Alaska's present reserve position and potentially recoverable undiscovered resources will require time, large amounts of capital and technological progress to make them available. The regulatory "price" we pay--in terms of delays, added costs, and market inflexibility--must be reduced to a minimum.

The complex environmental considerations and challenges inherent to the development of these gas resources must be met in a timely and responsible fashion. Intensive research and development needs to be undertaken to work toward the movement of the large quantities of uneconomic resources, presently generally classified as unconventional, to the proved reserve category. Much of this work is underway, but much more needs to be done to maintain an adequate domestic gas supply.

Canada and Mexico each possess significant natural gas resources which may be available to supplement our indigenous resource base.

I am optimistic about the continued development of our Nation's natural gas resources if we can move in the directions that I have indicated in a timely manner. None of these goals will be easily or quickly attained, but I am confident they can be accomplished.

I would be pleased to respond to questions, Mr. Chairman. As always, the Energy Information Administration stands ready to meet the energy data needs of the Subcommittee.

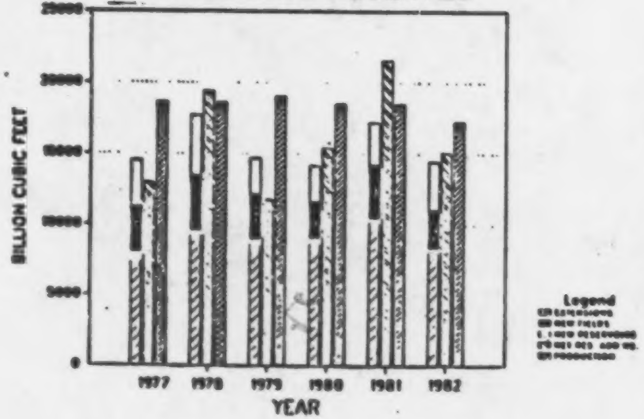
TABLE 1
LOWER-48 STATES END-OF YEAR DRY NATURAL GAS RESERVES
(IN BCF AND AS A PERCENT OF TOTAL LOWER-48 STATES)

STATE & SUBDIVISION	1977	1978	1979	1980	1981	1982
Alabama.............	530	514	652	636	648	648
Percent	0.30	0.29	0.39	0.38	0.38	0.39
Arkansas............	1,660	1,681	1,703	1,774	1,801	1,958
Percent	0.95	0.96	1.01	1.07	1.07	1.18
California..........	4,737	4,947	5,022	5,414	5,617	5,552
Percent	2.70	2.81	2.98	3.27	3.33	3.33
Onshore............	4,373	4,488	4,469	4,836	4,623	4,359
Percent	2.50	2.55	2.65	2.92	2.74	2.62
Offshore...........	364	459	553	578	994	1,193
Percent	0.21	0.26	0.33	0.35	0.59	0.72
Colorado............	2,512	2,765	2,608	2,922	2,961	3,314
Percent	1.43	1.57	1.55	1.76	1.76	1.99
Florida.............	151	119	77	84	69	64
Percent	0.09	0.07	0.05	0.05	0.04	0.04
Kansas..............	11,457	10,992	10,243	9,508	9,860	9,724
Percent	6.54	6.25	6.07	5.74	5.84	5.84
Kentucky............	451	545	468	508	530	551
Percent	0.26	0.31	0.28	0.31	0.31	0.33
Louisiana...........	57,010	55,725	50,042	47,325	47,377	44,916
Percent	32.55	31.66	29.66	28.57	28.08	26.97
North..............	3,135	3,203	2,798	3,076	3,270	2,912
Percent	1.79	1.82	1.66	1.86	1.94	1.75
South Onshore......	18,580	17,755	13,994	13,026	12,645	11,801
Percent	10.61	10.09	8.29	7.86	7.50	7.09
Offshore...........	35,295	34,767	33,250	31,223	31,462	30,203
Percent	20.15	19.76	19.71	18.85	18.65	18.14
Michigan............	1,386	1,422	1,204	1,406	1,118	1,084
Percent	0.79	0.81	0.71	0.85	0.66	0.65
Mississippi.........	1,437	1,635	1,504	1,769	2,035	1,796
Percent	0.82	0.93	0.89	1.07	1.21	1.08
Montana.............	887	926	825	1,287	1,321	847
Percent	0.51	0.53	0.49	0.78	0.78	0.51
North Dakota........	361	374	439	537	581	629
Percent	0.21	0.21	0.26	0.32	0.34	0.38
New Mexico..........	12,000	12,688	13,724	13,287	13,870	12,418
Percent	6.85	7.21	8.13	8.02	8.22	7.46
East...............	3,848	3,889	4,031	3,530	3,598	3,432
Percent	2.20	2.21	2.39	2.13	2.13	2.06
West...............	8,152	8,799	9,693	9,757	10,272	8,986
Percent	4.65	5.00	5.74	5.89	6.09	5.40
New York............	165	193	211	208	264	229
Percent	0.09	0.11	0.13	0.13	0.16	0.14
Ohio................	495	684	1,479	1,699	965	1,141
Percent	0.28	0.39	0.88	1.03	0.57	0.69
Oklahoma............	13,889	14,417	13,816	13,138	14,699	16,207
Percent	7.93	8.19	8.19	7.93	8.71	9.73
Pennsylvania........	769	899	1,515	951	1,264	1,429
Percent	0.44	0.51	0.90	0.57	0.75	0.86
Texas...............	56,422	55,383	53,021	50,287	50,469	49,757
Percent	32.21	31.58	31.42	30.36	29.92	29.88
South & Gulf Coast	21,620	20,179	18,534	16,992	16,947	16,551
Percent	12.34	11.47	10.98	10.26	10.05	9.94
East & Central....	5,568	6,189	5,864	6,771	7,184	7,542
Percent	3.18	3.52	3.48	4.09	4.26	4.53
Panhandle..........	7,764	7,406	6,784	6,435	6,229	6,210
Percent	4.42	4.21	4.02	3.88	3.69	3.73
West...............	16,189	15,387	13,974	12,579	12,120	11,896
Percent	9.24	8.74	8.28	7.59	7.18	7.14
Offshore...........	5,301	6,422	7,865	7,510	7,989	7,558
Percent	3.03	3.65	4.66	4.53	4.74	4.54
Utah................	877	925	948	1,201	1,912	2,161
Percent	0.50	0.53	0.56	0.73	1.13	1.30
West Virginia.......	1,567	1,634	1,558	2,422	1,834	2,148
Percent	0.89	0.93	0.92	1.46	1.09	1.29
Wyoming.............	6,305	7,211	7,526	9,100	9,307	9,758
Percent	3.60	4.10	4.46	5.49	5.52	5.86
Miscellaneous.......	102	109	153	176	191	191
Percent	0.06	0.06	0.09	0.11	0.11	0.11
Lower-48 States....	175,170	173,988	168,738	165,639	168,693	166,522
Percent	100.00	100.00	100.00	100.00	100.00	100.00

TABLE 2
LOWER 48 STATES
SUMMARY STATISTICS
(IN BCF)

Year	Net of Corrections, Adjustments and Revisions	Extensions	New Field Discoveries	New Reservoir Discoveries	Total Discoveries	Net Reserve Additions	Production	Year-End Reserves	R/P
1977	-1,561	8,056	3,173	3,301	14,530	12,969	18,637	175,170	9.4
1978	1,688	9,582	3,860	4,277	17,719	19,407	18,589	175,988	9.5
1979	-2,909	8,949	3,173	2,566	14,688	11,779	19,029	168,738	8.9
1980	1,225	9,046	2,539	2,577	14,162	15,387	18,486	165,639	9.0
1981	4,346	10,485	3,731	2,996	17,210	21,556	18,502	168,693	9.1
1982	619	8,349	2,687	3,419	14,455	15,074	17,243	166,522	9.7
Cumulative	3,408	54,467	19,163	19,136	92,764	96,172	110,486		

LOWER–48 STATES
ANNUAL PRODUCTION AND
CHANGES TO RESERVES



LOWER–48 STATES
YEAR–END RESERVES AND R/P RATIO

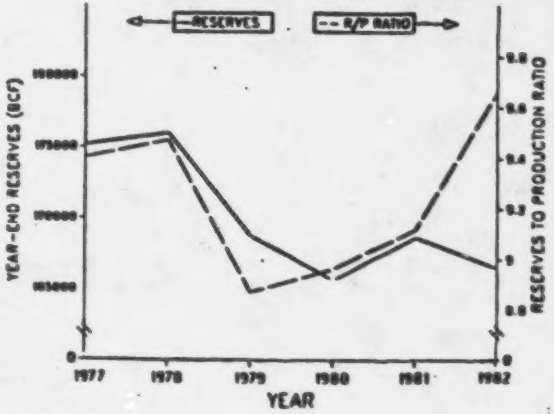
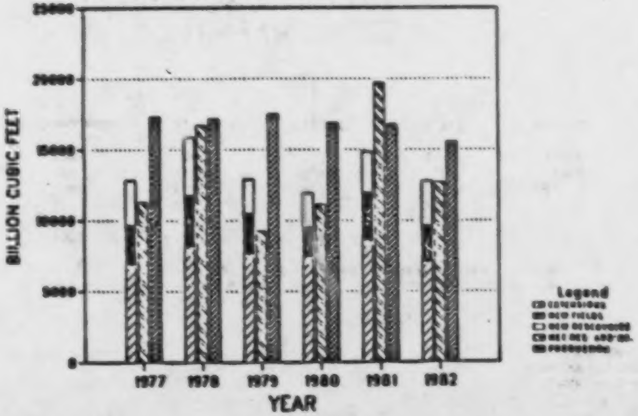


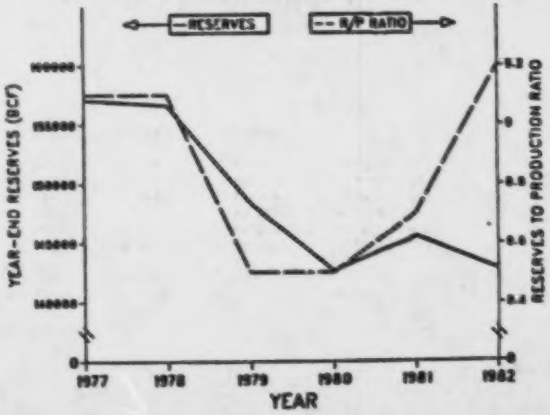
TABLE 3
TOTAL ALL MAJOR AREAS
SUMMARY STATISTICS
(IN BCF)

Year	Net of Corrections, Adjustments and Revisions	Extensions	New Field Discoveries	New Reservoir Discoveries	Total Discoveries	Net Reserve Additions	Production	Year-End Reserves	R/P
1977	-1,550	6,935	2,756	3,148	12,839	11,289	17,327	157,083	9.1
1978	818	8,205	3,586	4,093	15,884	16,702	17,169	156,616	9.1
1979	-3,645	7,686	2,819	2,407	12,912	9,267	17,511	148,372	8.5
1980	-787	7,485	2,039	2,414	11,938	11,151	16,878	142,645	8.5
1981	4,862	8,638	3,340	2,878	14,856	19,718	16,781	145,582	8.7
1982	-74	7,126	2,505	3,159	12,790	12,716	15,518	142,780	9.2
Cumulative	-376	46,075	17,045	18,099	81,219	80,843	101,184		

TOTAL ALL MAJOR AREAS
ANNUAL PRODUCTION AND
CHANGES TO RESERVES



TOTAL ALL MAJOR AREAS
YEAR-END RESERVES AND R/P RATIO



EXPLANATORY NOTES TO TABLES 1, 2, and 3

1. All volumes include both nonassociated and associated - dissolved gas; i.e., they are total gas quantities.

2. All volumes are expressed on a dry gas basis. Dry-gas volumes are those which remain after liquefiable hydrocarbons have been removed through lease, field, and/or plant separation. Nonhydrocarbon gases are excluded where they occur in sufficient quantity to render the gas unmarketable.

3. All volumes are reported in billions of cubic feet at 14.73 psia and 60 degrees Fahrenheit.

4. For 1982, offshore volumes for Louisiana include certain offshore Alabama components. This manner of reporting was required to avoid disclosure of confidential company-specific data.

5. Additional data are available in the individual Annual Reserve Reports for certain areas; e.g., data are available for each Texas Railroad Commission District.

6. For the purposes of this testimony, the Texas Railroad Commission Districts were combined as follows:

   - South and Gulf Coast Texas includes Districts 1, 2, 3, and 4.
   - Central and East Texas includes Districts 5, 6, 7B, and 9.
   - Texas Panhandle is comprised of District 10.
   - West Texas includes Districts 7C, 8, and 8A.

7. The Miscellaneous category includes the States of Arizona, Illinois, Indiana, Maryland, Nebraska, Nevada, Oregon, South Dakota, Tennessee, Virginia, and Washington. Data for each of these States are not necessarily present each year.

REFERENCES

The following publications or other documents are referenced and included in the testimony. Additional copies can be obtained by calling the Energy Information Administration's National Energy Information Center at (202) 252-8800.

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2. Competition and Other Current Issues in the Natural Gas Market, Service Report, RNGD 84-02, Office of Oil and Gas, Energy Information Administration, U.S. Department of Energy.
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6. "The Mexican Natural Gas Situation - An Overview", Natural Gas Monthly, DOE/EIA-0130(83), October 1983.
7. The Petroleum Resources of Mexico, Foreign Energy Supply Assessment Series, DOE/EIA-0423, October 1983.
8. "Exploring for Oil and Gas", Monthly Energy Review, DOE/EIA-0035(83), November 1983.
9. "The Influence of Federal Actions on Petroleum Exploration", Monthly Energy Review, DOE/EIA-0035(83)[2], December 1983 [2].

Senator **Murkowski**. Thank you, Mr. Evered. I will hold my questions until the entire panel has completed their testimony.

Our next witness is Mr. Terry Offield, Chief, Office of Energy and Marine Resources, U.S. Geological Survey, Department of the Interior.

We welcome you to the committee. We look forward to your testimony. Please proceed, Mr. Offield.

STATEMENT OF TERRY W. OFFIELD, CHIEF, OFFICE OF ENERGY AND MARINE GEOLOGY, U.S. GEOLOGICAL SURVEY, DEPARTMENT OF THE INTERIOR

Mr. **Offield**. Thank you, Mr. Chairman.

I appreciate the opportunity to discuss the natural gas resource picture of North America. I'll summarize a longer statement that I ask be entered for the record.

Senator **Murkowski**. It will be entered into the record.

Mr. **Offield**. Focusing first on the United States, there are a couple of important things to highlight.

First, large fields are of critical importance. Out of the total of about 9,000 U.S. gas fields, just the top 100 fields contain probably half our estimated reserves. In the search for large fields, there are not many places left that are likely to have those all-important large fields. Second, in the last few years, drilling around known fields has moved considerable gas from inferred reserves to measured reserves, but we cannot expect old fields to grow in reserves forever.

To satisfy our requirements take discoveries of new fields, but these tend annually, to replace only about half of the amount we need.

The most recent U.S. Geological Survey estimates were published in 1981 as circular 860. This was a work of several years, involving as many as 80 geologists. We estimated a range of 475 to 740 Tcf for undiscovered recoverable resources, with a mean of 594 Tcf.

Four years after circular 860, we still consider the estimated range to be reasonable, but disappointments like Georges Bank and the Mukluk well in the Beaufort Sea suggest that the low end of the estimated range is more likely to be realistic. We will have conventional natural gas for a long time, but in ever-decreasing amounts.

I would like to summarize the prospects for significant new discoveries in a few key regions of the United States. The Gulf of Mexico, and gulf coast resources will be brought in from many small to large fields, but this is a unique area, where one-well fields can be economic. There's also the deep Tuscaloosa trend, informally judged to have on the order of perhaps 15 Tcf.

Other major exploration areas are basins like the Anadarko basin of Oklahoma, or several basins in the Rocky Mountains, containing gas at depths of 15,000 to 25,000 feet, but much more drilling is needed to delineate the deep resource potential. There are problems in deep basins though—not all the gas is trapped below effective seals, and some of the deep reservoir rocks are relatively impermeable and will require costly extraction techniques to produce the gas.

The western overthrust belt is a very rich province, with much area and many deep parts still to be drilled. Major undiscovered gas resources are expected there, but toward the north some area is not available for exploration. Toward the south, two deep wells have been disappointing, and some geologists even doubt the presence of the overthrust belt across Arizona.

The eastern overthrust belt, first identified by the USGS, extends from Maine to Georgia. We expect the occurrence of gas resources there, but these resources will be deep and expensive.

For "elephant country," a place for giant fields, we look especially to Alaska. It takes elephant-sized finds to be economic there.

Despite the disappointments of the national petroleum reserve and Mukluk, the eastern part of the North Slope, in the Arctic National Wildlife Refuge, has petroleum geology suggestive of significant resources but the area is relatively small.

Recent finds in the Beaufort Sea and similar favorable geology in the Chukchi Sea also suggest much promise.

In the Navarin basin, the source and reservoir rocks may not be optimal but the area is large; the sedimentary sequence is very thick; good structures have been seen in seismic profiles; and gas seepage is present.

In the Gulf of Alaska, the rocks do not seem likely to be good reservoirs or to have experienced temperatures to derive gas from the contained organic matter.

Onshore Alaska, south of the Brooks Range, certainly needs further study and drilling, but based on our knowledge of the regional geology we do not assign much gas potential to the area.

For Canada, the Geological Survey estimates were mentioned in the opening remarks. Major potential resources are predicted in the western basin, the Beaufort region, the Arctic Islands, and the eastern offshore region.

As in the United States, many of Canada's gas resources are assigned to remote areas where the economics of recovery will significantly hinder development.

The Mexico resource picture is not well known. Mexican Government statements indicate reserves and resources amounting to a probable range of 200 to 350 Tcf, which is a reasonable number.

In the World Energy Resources Program, we are assessing the gas resources potential of Mexico. For the northeast province, adjacent to Texas, we assign 22 to 126 Tcf, with a mean of 60 Tcf. Other major resources we have estimated are in the Reforma-Campeche area far to the south. Promising gas finds also have been reported from the Gulf of California.

The USGS progressively is improving the knowledge base concerning unconventional gas resources. It appears that they indeed will be resources of the future, although probably based on very different economics and completely different rates of production than we consider for conventional natural gas.

That concludes my statement. I'll be pleased to try to answer any questions you may have.

[The prepared statement of Mr. Offield follows:]

Statement
Terry W. Offield, Chief, Office of Energy and Marine Geology,
U.S. Geological Survey, Department of the Interior,
before the Subcommittee on Energy Regulation, Committee on Energy and
Natural Resources, U.S. Senate, April 26, 1984

Mr. Chairman, I appreciate the opportunity to discuss the natural gas resource picture of North America. I would like to focus first on the United States. There are a couple of important things to highlight. First, a large percentage of both oil and gas reserves occur in giant and supergiant fields. We have only 2 supergiant gas fields and only 17 giant fields. These few, and some large but not giant fields, are of critical importance. Out of the total of about 9,000 U.S. gas fields, just the top 100 fields contain probably half our estimated reserves. In the search for large fields there are many good producing areas to drill more wells in, and good frontier areas yet to explore properly, but there are not many places left that are likely to have those all-important giant fields. In the areas already reasonably explored, the easy-to-find resources have already been found. Second, in the last few years drilling around known fields has moved considerable gas from inferred reserves to measured reserves.[1] This is still a relatively easy resource transfer to make, but we cannot expect old fields to grow in reserves forever. To satisfy our requirements takes discoveries of new fields, but these tend, annually, to replace only about half of the amount we need. This situation could be remedied by finding new provinces and large fields, but--as I have said--that will be hard to do. As an alternative, many, many small but economic fields will have to be found. Either course will be difficult and undoubtedly slow and expensive.

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[1] Measured reserves--That part of the economic identified resource that is estimated from geologic evidence supported directly by engineering measurements. Measured reserves here are equivalent to proved reserves as defined by the American Petroleum Institute.

Undiscovered resources--Resources, outside of known fields, estimated from broad geologic knowledge and theory. Also included are resources from undiscovered pools that occur as unrelated accumulations controlled by distinctly separate structural features and (or) stratigraphic conditions within areas of known fields.

These highlighted points are important in considering the U.S. Geological Survey's (USGS) estimates of gas resources, because if the estimated resources are there to be found, then of course these points will affect the success of that search. The most recent USGS estimates were published in 1981 as Circular 860 (summary table attached). This was a work of several years, involving as many as 80 geologists. On top of 191 trillion cubic feet (TCF) of measured reserves and 177 TCF of inferred reserves, we estimated a range of 475 to 740 TCF for undiscovered recoverable resources, with a mean of 594 TCF. The range and mean reflect statistical probabilities, from high to low confidence, estimated by groups of experts considering for 137 provinces the petroleum geology, exploration histories, volumes of sedimentary rock, and known gas-to-oil ratios. These published estimates were based primarily on publicly available data; they are based on conventional technology and economics and they do not include tight gas sand or other unconventional gas resources. In gauging recoverability of resources, the estimates do reflect assumed economic thresholds such as minimum field sizes-and availability of delivery infrastructure; these could be very important factors in whether more gas than estimated might ultimately be producible in frontier areas like Alaska or deepwater areas of the continental slope.

Four years after Circular 860 we still consider the estimated range to be reasonable, but severe disappointments like Georges Bank, the Mukluk well in the Beaufort Sea and declining prospects for gas in deep basins suggest that the low end of the estimated undiscovered resource range is more likely to be realistic. But we have not yet formally updated our assessment. So, at today's prices and something like today's usage, there should yet be left to discover enough natural gas to last us perhaps 40 years--but that number really is meaningless, as it will take longer than that to find and produce it. Rates of discovery, rates of production, and many other relevant factors need to be taken into account to estimate how many years supply of natural gas remains for this country. We will have conventional natural gas for a long time, but in ever-decreasing amounts. However, it must be kept in mind that as prices rise, reflecting the relative scarcity of gas, there are increased incentives to drill for and discover new gas in areas such as Prudhoe Bay which are uneconomic at this time. It will not be as available as we will need and it seems safe to say it will be more costly.

In thinking about the prospects for significant new discoveries, I would like very briefly to summarize the likely resource picture in a few key regions of the United States. Small gas fields are found every day in many parts of the country; in fact, our biggest regional estimated resources--those for the Gulf of Mexico and Gulf Coast, as shown on the attached map--will be brought in from many small to large fields. But this is a unique area where one-well fields can be economic because delivery systems are so widespread. Also along the Gulf Coast is the deep Tuscaloosa trend, informally and perhaps optimistically judged to have on the order of perhaps 15 TCF.

Other major exploration areas, some of which may contain large fields, are basins like the Anadarko Basin of Oklahoma, containing gas in strata at depths of 15-25,000 feet. We believe the deep Anadarko has considerable potential, perhaps on the order of twice the estimated resources of the Tuscaloosa deep trend. In comparable deep parts of the Permian Basin of Texas or the Washakie, Wind River, and Big Horn Basins of the Rocky Mountains, much more drilling is needed to delineate the deep resource potential. There are problems in deep basins, though--not all the gas is trapped below effective seals, and some of the deep reservoir rocks are relatively impermeable or "tight" and will require costly extraction techniques to produce the gas.

The western overthrust belt is a very rich geological province, with much area and many deep parts still to be drilled. Major undiscovered gas resources are expected to be there (probably in excess of 20 TCF, or approximately the same as what has already been found), but toward the north some of the area is not available for exploration owing to restricted land use, and in part of the area the geology changes significantly. Toward the south, some geologists doubt the existence of the overthrust belt across Arizona and two deep wells have indeed been disappointing.

The eastern overthrust belt, first identified by the USGS, extends from Maine to Georgia. We expect the occurrence of gas resources there, most particularly in the southern area. These resources will be deep and expensive at best.

For "elephant" country, a place for giant fields, we look especially to Alaska. The area is so remote and the environment, both onshore and offshore, so difficult, that it takes elephant-sized finds to be economic. The Prudhoe Bay field discovered in 1968 contains 26 TCF, truly giant size, but the gas cannot yet be economically produced and delivered at this time. What else might be there? Despite the disappointments of the National Petroleum Reserve and Mukluk, the eastern part of the North Slope, in the Arctic National Wildlife Refuge, has good petroleum geology suggestive of significant resources but the area is relatively small. Recent finds in the Beaufort Sea and similar favorable overthrust geology of Paleozoic and Mesozoic rocks in the Chukchi Sea suggest much promise, though ice conditions inhibit exploration and development.

South of the Bering Straits, the best hope appears to be in the Navarin Basin. The source and reservoir rocks may not be optimal but the area is large, the sedimentary sequence is very thick, good structures have been seen in seismic profiles, and gas seepage is present. Exploration, though promising, will be difficult and extremely expensive; development will be hindered by the total absence of infrastructure. However, industry apparently is fairly optimistic if the recent lease sale results are a realistic measure. In the Gulf of Alaska, prospects are not as bright; exploration so far has been unrewarding, and the rocks do not seem likely to be good reservoirs or to have experienced temperatures of a level necessary to derive gas from the contained organic matter. Onshore Alaska, south of the Brooks Range, certainly needs further study and test drilling, but based on our knowledge of the regional geology we do not assign much gas potential to the area.

For Canada, the Geological Survey of Canada estimates gas reserves at 103 TCF and potential resources at 326 TCF ("average expectation"). Two-thirds of the reserves are in the Western Canada Sedimentary Basin. Of the potential resources, 86 TCF are in the Western Basin, 64 TCF in the Mackenzie Delta-Beaufort area, 77 TCF in the Arctic Islands, and 83 TCF in the eastern offshore region. A "high confidence" estimate is about half the "average expectation." In the Western Basin, there is room for undiscovered large fields, many small, subtle traps are expected, and the overthrust belt is not well explored. In the Beaufort region, three near-giant fields cause some optimism that resources will be about 7 times those presently explored. The Arctic Islands area is poorly tested, but 18 fields (not all economic at this time) have been discovered; the best gas prospects are in the Sverdrup Basin. In the eastern offshore region, estimates for undiscovered resources are about 10 times the discovered gas; the largest resources are assigned to the Labrador Shelf, the Scotian Shelf (especially the Venture field), and the East Newfoundland area, which includes the Hibernia field (about 2 TCF). As in the United States, many of Canada's gas resources are assigned to remote areas where the economics of recovery will significantly hinder development.

The Mexico resource picture is not well known. Mexican government statements indicate reserves and resources amounting to a probable range of 200 to 350 TCF, which is reasonable. In the World Energy Resources Program, we are preparing reports on Mexico and expect to be able to independently assess the gas resource potential of Mexico. So far we have completed preliminary reports on two provinces. For the northeast province adjacent to Texas the resulting estimate assigns 22 to 126 TCF (mean 60 TCF) to the Sabinas-Burgos-Parras Basin region. The Sabinas Basin in particular has good source and reservoir rocks, promising anticlinal structures for traps, and proper seals to hold gas resources. There are more than 75 known large structures, and only a few have been tested--but with a good success rate. The Burgos Basin is less promising but has potential for deep traps. The Parras Basin is prospective for both thermogenic and biogenic gas. This region is especially important because of its proximity to the United States, assuming international agreements and transportation lines can be arranged so that the gas will be available for U.S. import. Other major resources we have estimated are in the Reforma-Campeche area far to the south, but we understand that this gas is slated for consumption in Mexico. Promising gas finds also have been reported from the Gulf of California.

The USGS progressively is improving the knowledge base concerning unconventional gas resources, and in particular we work with the Department of Energy on the geology of western tight gas sands and eastern Devonian shales. Along with geopressured methane and methane from coal beds, these resources are reputed--typically on not nearly enough information--to be very large, perhaps several times the amount of conventional gas once in place. But each will involve costly engineering procedures and the amount that may be economically recoverable is impossible to assess at this time. We can assume, however, that owing to the dispersed nature of these vast resources, the rates of production will be much less than for conventional resources. Another potential resource may be layers of gas hydrates at shallow depths offshore around Alaska and on the Atlantic continental shelf. This possible resource is even more poorly known or understood. We have research projects underway on all these unconventional kinds of hydrocarbons in order to gain an understanding of their occurrence and potential. It appears that they indeed will be resources of the future, although probably based on very different economics and completely different rates of production than we consider for conventional natural gas.

That concludes my statement. I will be pleased to try to answer any questions you may have concerning our work or the gas resource picture.

Table 7.--Total gas--Production, reserves, and estimates of undiscovered recoverable resources of the United States

[A[illegible]ulated values are rounded numbers; therefore values for production and reserves and for means of [illegible]covered resources, all of which are additive, may not be precisely so. Values shown are in trillion cubic feet. Negl., negligible, less than or equal to 0.05 trillion cubic feet of gas]

Petroleum Region	Cumulative production[1]	Identified resources[1,2]		Undiscovered recoverable resources			
		Measured reserves	Inferred reserves	Low [3]F_{95}	High [3]F_5	Mean	Standard deviation
Onshore							
1 Alaska	1.2	30.0	4.6	19.8	62.3	36.6	14.0
2 Pacific Coast	27.0	4.2	3.8	8.2	24.9	14.7	5.5
3 Colorado Plateau and Basin and Range	15.0	11.4	4.5	53.5	142.4	90.1	29.7
4 Rocky Mountains and northern Great Plains	13.2	7.1	5.5	29.6	69.0	45.7	12.6
5 West Texas and eastern New Mexico	70.7	15.9	18.1	22.4	75.2	42.8	17.8
6 Gulf Coast	228.5	45.3	76.3	56.5	249.1	124.6	63.6
7 Mid-continent	127.8	32.0	18.8	22.9	80.8	44.5	18.4
8 Michigan Basin	1.3	1.1	1.1	1.8	10.9	5.1	3.1
9 Eastern Interior	1.8	Negl.	0.1	1.2	5.0	2.7	1.3
10 Appalachians	36.2	6.2	5.9	6.4	45.8	20.1	13.2
11 Atlantic Coast	Negl.	Negl.	Negl.	Negl.	0.4	0.1	0.3
Entire onshore	520.6	153.3	136.5	322.5	567.9	426.8	78.5
Offshore—shelf							
1A Alaska[4]	0.6	2.0	1.2	28.5	99.0	57.6	23.6
2A Pacific Coast	1.5	1.9	0.4	0.9	5.2	2.5	1.5
6A Gulf of Mexico	55.3	[5]36.4	[5]39.5	22.0	79.2	45.3	18.5
11A Atlantic Coast	0	0	0	2.2	17.9	8.2	5.0
Entire shelf	57.5	38.2	41.0	72.0	166.8	113.6	30.6
Offshore—slope							
1A Alaska[4]	0	0	0	0	20.2	7.2	12.3
2A Pacific Coast	0	0	0	1.9	10.2	4.4	3.3
6A Gulf of Mexico	Negl.	No data[5]	No data[5]	11.1	51.8	26.5	13.8
11A Atlantic Coast	0	0	0	5.1	34.5	15.6	9.6
Entire slope	0	0	0	28.6	87.1	53.9	21.0
Offshore—combined shelf and slope							
1A Alaska[4]	0.6	2.0	1.2	33.3	109.6	64.8	26.6
2A Pacific Coast	1.5	1.9	0.4	3.7	13.0	6.9	3.3
6A Gulf of Mexico	55.3	36.4	39.5	41.7	114.2	71.8	23.1
11A Atlantic Coast	0	0	0	9.2	42.8	23.7	10.8
Entire offshore	57.5	38.2	41.0	117.4	230.6	167.2	37.2
Combined onshore and offshore							
Entire United States	578.0	191.5	177.5	474.6	739.3	593.8	85.8

[1] Cumulative production and reserves are as of December 31, 1979. Production and reserve figures were derived from API and AGA data (American Petroleum Institute, American Gas Association, and Canadian Petroleum Association, 1980) except for California for which production and reserve data were taken from California Division of Oil and Gas (1980) and the U.S. Geological Survey ([illegible], 1947).

[2] Does not include gas in storage.

[3] F_{95} denotes the 95th fractile; the probability of more than the amount F_{95} is 95 percent. F_5 is defined similarly. Fractile values are not additive.

[4] Includes quantities considered recoverable only if technology permits their exploitation beneath Arctic pack ice—a condition not yet met.

[5] API and AGA reserve data for the Gulf of Mexico are not available within separate shelf and slope classifications. However, the declared reserves probably represent only the shelf and are so treated.

From U.S. Geological Survey Circular 860, 1981.

ATTACHMENT

and produced quantities provide a frame of reference for the estimates of undiscovered resources.

The undiscovered recoverable oil of the United States is estimated to range from 64.3 to 105.1 billion barrels with a mean estimate of 82.6 billion barrels. The undiscovered recoverable gas is estimated to range from 474.6 to 739.3 trillion cubic feet with a mean estimate of 593.8 trillion cubic feet. Each range corresponds to 95 percent and 5 percent probabilities of *more than* the respective amounts.

The geographic distribution of estimated undiscovered resources is shown graphically in figures 13 and 14 and is further compared as percentage distributions in figures 15 and 16. Resources are not uniformly distributed; a few Regions contain most of the estimated undiscovered oil and gas. First, 66 percent of the mean estimate for undiscovered oil and 72 percent for gas is onshore. Almost 90 percent of the onshore potential is found in 6 of the 11 Regions (namely 1 and 3 through 7). Similarly, of the offshore Regions, the Gulf of Mexico plus Alaska contain 67 percent of the oil potential and 82 percent of the gas potential. Analysis of the detailed tables of province estimates in Appendixes C and D indicates that commonly a few individual provinces in each of the Regions (for

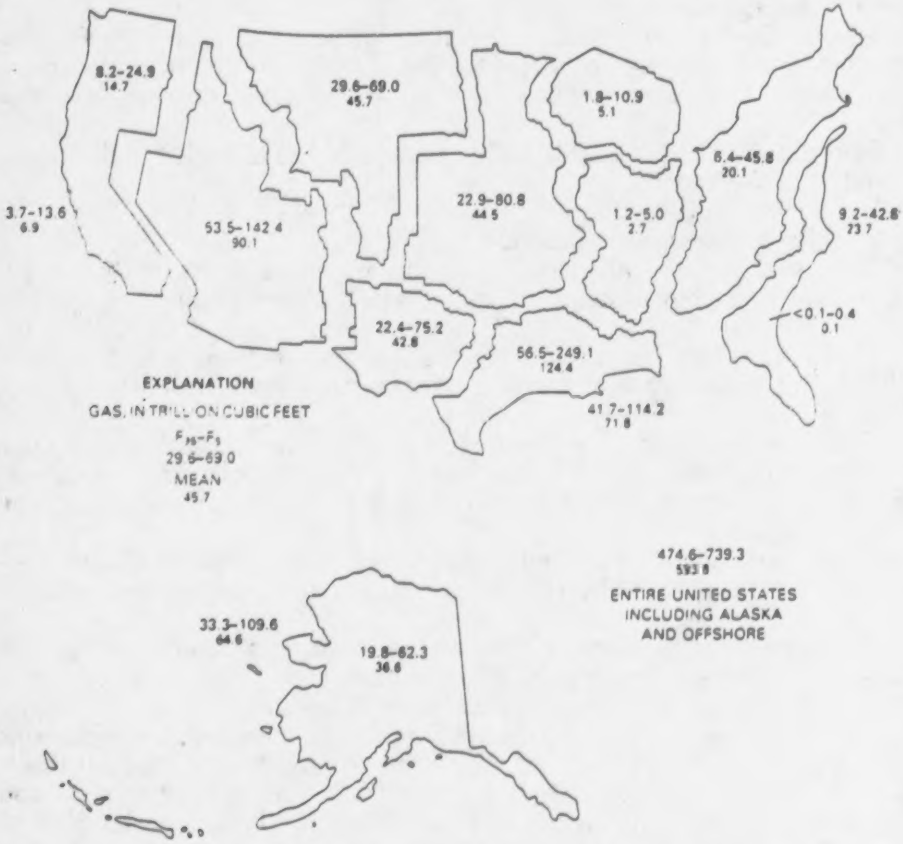
8.2-24.9
14.7
29.6-69.0
45.7
1.8-10.9
5.1
8.4-45.8
20.1
3.7-13.6
6.9
53.5-142.4
90.1
22.9-80.8
44.5
1.2-5.0
2.7
9.2-42.8
23.7
<0.1-0.4
0.1
22.4-75.2
42.8
56.5-249.1
124.4
41.7-114.2
71.8
EXPLANATION
GAS, IN TRILLION CUBIC FEET
F_{95}-F_5
29.6-69.0
MEAN
45.7
474.6-739.3
593.8
ENTIRE UNITED STATES
INCLUDING ALASKA
AND OFFSHORE
33.3-109.6
64.6
19.8-62.3
36.6

Figure 14.--Total natural gas--Ranges and means of undiscovered recoverable resource by Region.

From U.S. Geological Survey Circular 860, 1981.

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Senator **Murkowski**. Thank you, Mr. Offield.

We will, again, hold questions until the end.

Our next witness is Dr. Harry Kent, director of the Potential Gas Agency, Colorado School of Mines.

We welcome you before this subcommittee, and encourage you to proceed with your testimony.

STATEMENT OF DR. HARRY C. KENT, PROFESSOR OF GEOLOGY AND DIRECTOR, POTENTIAL GAS AGENCY, COLORADO SCHOOL OF MINES

Dr. **Kent**. Thank you, Mr. Chairman.

I appreciate the opportunity to be here this afternoon to speak before the subcommittee.

I have indeed prepared a written statement, and I have also made available copies of the yearend 1982 report of the Potential Gas Committee, and I would ask that these be entered into the record.

Senator **Murkowski**. All right. I have it here, and it will be entered into the record.

Dr. **Kent**. Thank you.

Senator **Murkowski**. Thank you.

Dr. **Kent**. As is indicated, much of my work deals with the supervision and coordination of the work of the members of the Potential Gas Committee.

The committee is an independent organization, comprised of about 150 members who work in the natural gas industry, or are closely affiliated with it.

They are organized for the purpose of preparing periodic reports on the recoverable resources of natural gas which in the best judgment of the committee members remain to be discovered in the United States.

Their estimates are based on the available geological and geophysical data and on the results of exploratory drilling and productions.

We endeavor to recruit committee members from among the most knowledgeable persons, mainly geologists and engineers, who have experience in the various areas of the country.

The areas which are considered include all prospective regions of the lower 48 States and Alaska. The estimates of potential resources which are presented represent most likely estimates, and are the quantify of natural gas which has the highest probability of being present and susceptible to discovery and production in the best judgment of the committee members.

They present neither the most optimistic viewpoint nor the most pessimistic.

I might state also that the periodic revision of the work of the committee will be completed again at the end of 1984. We will have a report available in mid-1985 giving the results of our reevaluation.

In the report to yearend 1982, the Potential Gas Committee concluded that more than one-half of the resource originally existing in the United States still remain to be found, and more than 60 percent of the original resource remain to be produced.

The total potential resource estimated by the committee, as mentioned previously by the subcommittee chairman, is approximately 876 Tcf. Forty-eight percent of the total U.S. resource, or approximately 420 Tcf, is estimated to occur in the lower 48 States at drilling depths less than 15,000 feet, or in offshore water depths less than 200 meters, or 656 feet.

These potential resources, in addition to proved reserves, are judged to be relatively accessible and to be amenable to future discovery and development with relatively moderate cost.

Gas resources occurring in the lower 48 States at drilling depths greater than 15,000 feet, down to a maximum depth of 30,000 feet, are estimated to be 274 Tcf, or 31 percent of the total U.S. potential. And similarly, 48 Tcf, or 5 percent, is estimated to occur beneath offshore water depths of 200 to 1,000 meters, or somewhat greater than 3,000 feet.

These resources at great depths, onshore, and beneath greater water depths offshore, are judged to be relatively more difficult to find and to develop, and to be relatively more expensive to produce. Thus, about 57 percent of the lower 48 resource potential is expected to be relatively accessible, and about 43 percent is expected to be relatively more difficult of access and development.

Alaskan resources and potential are less well known that those of the lower 48 States. And proportionately, more of the Alaskan potential is in the speculative category, about which there is considerable uncertainty regarding the actual magnitude of the resource.

The most likely estimate of the Alaskan potential is 134 Tcf, or 15 percent of the total U.S. resource potential. Fifty Tcf of the Alaskan potential is judged to occur in onshore areas, and 84 Tcf in offshore areas.

The resource estimates of the Potential Gas Committee are presented in terms of three categories: probable, possible, and speculative.

These categories relate to the varying degrees of geologic knowledge of the resource potential, and to the degree of uncertainty associated with the estimates.

The magnitude of probable resources is known with a reasonable degree of certainly, because these resource estimates which are similar to the USGS category of inferred reserves relate to resources yet to be developed in fields which are already discovered.

Possible resources have a higher degree of uncertainty, because they relate to resources estimated to exist in fields which have not yet been discovered within geologic provinces and formations, however, where production has been established previously in older fields.

Speculative resources carry the highest degree of uncertainty about both their existence and the magnitude of the resource, because they are postulated to exist in undiscovered fields in geologic provinces, and in formations which have not yet been proven to be productive.

The distribution of resources in the three categories can also be viewed as representing in a general way the gradual shift of exploratory and development activities through the years into those areas in which the speculative potential lies.

This will reflect a gradual depletion of the probable and possible resources and development of the speculative. It is anticipated that this will become an increasingly important factor in the remaining years of this century and into the 21st century, as the focus of exploration moves more and more into the Rocky Mountain region and portions of the Appalachian regions of the lower 48 States, in addition to the midcontinent areas of Oklahoma. And also, as mentioned previously, Alaska has a large proportion of speculative resources.

Many of the potential reservoir rocks in the areas of speculative resources have lower permeabilities than the reservoir rocks currently producing in the gulf coast regions.

This means that even though the resources may be large, it will not be possible to produce the gas as rapidly as can be done from the gulf coast reservoirs, and that it will be more difficult to maintain a daily or annual rate of production comparable to that experienced currently or in recent years.

The fields will produce for a longer period of time, but the gas will come out of the reservoir rock at a slower rate. More fields will have to be discovered, and more wells will have to be drilled in order to maintain production levels. This means greater investment and a slower return on investment.

These factors contribute to the conclusion reached by a number of studies, that the quantity of gas on a daily basis which will be available in the latter part of the 20th century will be less than the current availability.

In addition to work with the Potential Gas Committee, I have been involved in a study of the economics of the cost of development of the U.S. natural gas potential based on the work of the committee.

This study is now drawing to a close, and I can report very briefly on the preliminary results of our first analyses.

We have completed work on the nonassociated gas potential in the Permian basin of west Texas and southeastern New Mexico, and the interior salt basin of Mississippi and Alabama.

For the Permian basin, we estimate that the nonassociated gas potential could be found and developed for an average cost of approximately $3.63 per thousand cubic feet. This is in constant 1980 dollars.

For the interior salt basin, we estimate that the average cost to find and develop these nonassociated gas potential would be approximately $4.12 per Mcf.

These costs include allowance for exploration, land, drilling, completion, well site equipment, production, overhead, taxes, and return on investment. Costs of transportation from the well to the consumer are not included.

These preliminary cost estimates apply, of course, only to the two basins mentioned, and we expect that the cost for other areas will vary.

The cost of development of the resource potential from smaller fields at greater depths, and in the speculative category will be higher than for the resources in larger fields at shallower depths and in the probable and possible categories.

However, our work so far indicates that much of the resource potential which is estimated by the Potential Gas Committee members will be available at costs which are consistent with current economics. By this I mean at a relationship between cost and price which is of the same order of magnitude as the current relationship.

To summarize, the results of the work of the Potential Gas Committee and of our economic studies currently underway at Colorado School of Mines would indicate:

One. There is considerable resource potential for natural gas remaining in both the lower 48 States and Alaska.

Two. The magnitude of this resource potential is approximately equal to the total cumulative production in the history of the United States, plus the current proved reserves.

Three. About 60 percent of the original resource potential remains in the ground in the form of proved reserves, or potential resources.

Four. A sizable portion of the resource potential—almost one-half—exists in areas which are relatively accessible and relatively inexpensive to develop.

Five. About one-third of the resource potential lies in areas of the lower 48 States which are relatively difficult and expensive to explore and develop. By this I mean deep portions of onshore basins and beneath deep water offshore.

Six. Fifteen percent of the total U.S. potential is estimated to occur in Alaska, both onshore and offshore.

Seven. Much of the resource potential can be developed at costs which are consistent with current economics.

Thank you very much, Mr. Chairman.

[The prepared statement of Dr. Kent follows:]

ORAL STATEMENT
OF
HARRY C. KENT
before the
Subcommittee on Energy Regulation
United States Senate
April 26, 1984

Good afternoon. My name is Harry C. Kent. I am a Professor of Geololgy at the Colorado School of Mines, Golden, Colorado, and I am also Director of the Potential Gas Agency of the School.

Much of my work deals with supervision and coordination of the work of the members of the Potential Gas Committee. The Potential Gas Committee is an independent organization comprised of about 150 members who work in the natural gas industry or are closely affiliated with it. They are organized for the purpose of preparing periodic reports on the recoverable resources of natural gas which, in the best judgment of the Committee members, remain to be discovered in the United States. Their estimates are based on the available geological and geophysical data and on the results of exploratory drilling and production. We endeavor to recruit Committee members from among the most knowledgeable persons, mainly geologists and engineers, who have experience in the various areas of the country. The areas which are considered include all prospective regions of the lower 48 states and Alaska. The estimates of potential resources which are presented represent "most likely" estimates and are the quantity of natural gas which has the highest probability of being present and susceptible to discovery and production, in the best judgment of the Committee members. They represent neither the most optimistic viewpoint nor the most pessimistic.

I have prepared a written statement which includes a summary of the estimates of the Committee based upon their most recent report which includes consideration of all data available through the end of 1982. In addition, I have provided copies of this year-end 1982 report for the members of the Subcommittee in case they should wish to review the estimates in more detail or to learn more about the work and procedures of the Potential Gas Committee. I ask that these documents be entered into the record. In my oral statement I wish to emphasize a few of the points which are contained in my written statement and in the Committee report. Incidentally, Potential Gas Committee members are currently working on revised estimates which will be based on information available through the end of 1984. This report will be available mid-1985.

In the report for year-end 1982, the Potential Gas Committee concluded that more than one-half of the resource originally existing in the United States still remained to be found, and more than 60% of the original resource remained to be produced. The total potential resource estimated by the Committee is approximately 876 trillion cubic feet (Tcf) in addition to proved reserves. Forty-eight percent of the total U.S. resource, or approximately 420 Tcf, is estimated to occur in the lower 48 states at drilling depths less than 15,000 feet or in offshore water depths less than 200 meters (656 feet). These potential resources are judged to be relatively accessible and to be amenable to future discovery and development with relatively moderate cost. Gas resources occurring in the lower 48 states at drilling depths greater than 15,000 feet, down to 30,000 feet, are estimated to be 274 Tcf, or 31% of the total U.S. potential. Similarly, 48 Tcf, or 5%, is estimated to occur beneath offshore water depths of 200 to 1,000 meters (3,280 feet). These resources at great depths onshore and beneath greater water depths offshore are judged to be relatively more difficult to find and to develop and to be relatively more expensive to produce. Thus about 57% of the lower 48 resource potential is expected to be relatively accessible and about 43% is expected to be relatively more difficult of access and development.

Alaskan resources and potential are less well known than those of the lower 48 states, and proportionately more of the Alaskan potential is in the Speculative category about which there is considerable uncertainty regarding the actual magnitude of the resource. The "most likely" estimate of the Alaskan potential is 134 Tcf, or 15% of the total U.S. resource potential. Fifty trillion cubic feet of the Alaskan potential is judged to occur in onshore areas and 84 Tcf in offshore areas.

The resource estimates of the Potential Gas Committee are presented in terms of three categories: Probable, Possible and Speculative. These categories relate to the varying degrees, of geologic knowledge of the resource potential and to the degree of certainty associated with the estimates. The magnitude of Probable resources is known with a reasonable degree of certainty because these resource estimates relate to resources yet to be developed in fields which are already discovered. Possible resources have a higher degree of uncertainty because they relate to resources estimated to exist in fields which have not yet been discovered within geologic provinces and in formations where production has been established previously in older fields. Speculative resources carry the highest degree of uncertainty about both their existence and the magnitude of the resource because they are postulated to exist in undiscovered fields in geologic provinces and in formations which have not yet been proven to be productive.

The distribution of resources in the three categories can also be viewed as representing, in a general way, the gradual shift of exploratory and development activities through the years into those areas in which the Speculative potential lies. This will reflect a gradual depletion of the Probable and Possible resources and development of the Speculative. It is anticipated that this will become an increasingly important factor in the remaining years of this century and into the 21st century as the focus of exploration moves more and more into the Rocky Mountain region and portions of the Appalachian region in addition to the Mid-Continent area of Oklahoma. As mentioned previously, Alaska also has a large proportion of Speculative resources.

Many of the potential reservoir rocks in the areas of Speculative resources have lower permeabilities than the reservoir rocks currently producing in the Gulf Coast region. This means that, even though the resources may be large, it will not be possible to produce the gas as rapidly as can be done from the Gulf Coast reservoirs and that it will be more difficult to maintain a daily or annual rate of production comparable to that experienced currently or in recent years. The fields will produce for a longer period of time, but the gas will come out of the reservoir rock at a slower rate. More fields will have to be discovered and more wells will have to be drilled in order to maintain production levels. This means greater investment and a slower return on investment. These factors contribute to the conclusion reached by a number of studies that the quantity of gas on a daily basis which will be available in the latter part of the 20th century will be less than the current availability.

In addition to work with the Potential Gas Committee, I have been involved in a study of the economics of the cost of development of the U.S. natural gas potential based on the work of the Potential Gas Committee. This study is now drawing to a close, and I can report very briefly on the preliminary results of our first analyses. We have studied the Permian basin of west Texas and southeastern New Mexico and the Interior Salt basin of Mississippi and Alabama. For the Permian basin we estimate that the nonassociated gas potential could be found and developed for an average cost of approximately $3.63 per Mcf (thousand cubic feet) in constant 1980 dollars. For the Interior Salt basin we estimate that the average cost to find and develop the nonassociated gas potential would be approximately $4.12 per Mcf. These costs include allowance for exploration, land, drilling, completion, well-site equipment, production, overhead, taxes and return on investment. Costs of transportation from the well to the consumer are not included. These preliminary cost estimates apply only to these two basins and we expect that the costs for other areas will vary. The cost of development of the resource potential from smaller fields, at greater depths and in the Speculative category will be higher than for the resources in larger fields, at shallower depths and in the Probable and Possible categories. Our work so far indicates that much of the resource potential will be available at costs which are consistent with current economics. By consistent with current economics, I mean at a relationship between cost and price which is of the same order of magnitude as the current relationship.

To summarize, the results of the work of the Potential Gas Committee and of the economic studies currently underway at the Colorado School of Mines indicate:

1. There is considerable resource potential for natural gas remaining in both the lower 48 states and in Alaska.

2. The magnitude of this resource potential is approximately equal

to the total cumulative production in the history of the United States natural gas industry plus the current proved reserves.

3. About 60% of the original resource potential remains in the ground in the form of proved reserves or potential resources which could be developed and produced in the future.

4. A sizable portion of the resource potential, almost one-half, exists in areas which are relatively accessible and relatively inexpensive to develop.

5. About one-third of the resource potential lies in areas of the lower 48 states which are relatively difficult and expensive to explore and develop--deep portions of onshore basins and beneath deep water offshore.

6. Fifteen percent of the total U.S. potential is estimated to exist in Alaska, both onshore and offshore.

7. Much of the resource potential can be developed at costs which are consistent with current economics.

STATEMENT OF HARRY C. KENT

Professor of Geology
and
Director, Potential Gas Agency
Colorado School of Mines

Before the
Subcommittee on Energy Regulation
United States Senate

April 26, 1984

INTRODUCTION

My name is Harry C. Kent. I am Professor of Geology and Director of the Potential Gas Agency at the Colorado School of Mines. My responsibility includes courses related to the geology of oil and natural gas. I also direct the work of the Potential Gas Agency of the Mineral Resources Institute, Colorado School of Mines, which is charged with directing the scientific work of the Potential Gas Committee in the preparation of estimates of undiscovered natural gas potential in the United States. The work of the Potential Gas Agency is conducted by the Colorado School of Mines under a contract with the American Gas Association. A summary of my educational and professional experience is contained in the biographical information which is attached to this testimony.

The resource information which I will be quoting in my testimony is derived from the work of the Potential Gas Committee. The Potential Gas Committee is a nonprofit, volunteer committee which is composed of approximately 150 members from the natural gas industry. Our members are primarily geologists and petroleum engineers. Their purpose, as members of the Potential Gas Committee, is to prepare periodic evaluations of the natural gas resource potential of the United States. They are particularly concerned with the undiscovered resource, or the potential for new field discoveries, in addition to that which has already been discovered and included in present proved reserves. The Committee issues a report every two years and revises its estimates based on the results of exploration and drilling activity in the preceding period. The latest report was prepared based on information available through the end of 1982. A revised report is currently in preparation and will be issued in 1985.

In addition, I will present some information from independent research being conducted by the Colorado School of Mines under a research contract sponsored by the Gas Research Institute and the Electric Power Research Institute. This study, of which I am the Principal Investigator, is concerned with evaluation of the cost of development of the natural gas resource potential which is estimated to exist by the Potential Gas Committee. A few preliminary results from this study are now available, although the bulk of the analysis of data is still to be accomplished.

U.S. NATURAL GAS POTENTIAL

Copies of the latest report of the Potential Gas Committee summarizing their review of geological, geophysical and engineering data available through the end of 1982 are being supplied to the Subcommittee members and staff. This report will provide the detailed background information on which my summary testimony is based.

It is the Committee's conclusion that more than one-half of the resource originally existing in the United States still remained to be found at the end of 1982 and, at that point, more than 60% of the original resource remained to be produced. The total potential resource estimated by the Committee is approximately 876 trillion cubic feet (Tcf). The Committee subdivides the resource potential into the categories of Probable, Possible and Speculative resources, and also provides separate estimates for each of twelve areas of the United States. Additionally, the estimates are given separately for onshore and offshore regions. In onshore regions the Committee has given separate estimates for the potential believed to exist above drilling depths of 15,000 feet and for the potential believed to exist at depths between 15,000 and 30,000 feet. In offshore regions the estimates are given separately for areas where the water depth is less than 200 meters and for areas in which the water depth is between 200 and 1,000 meters.

Probable resources are those resources in addition to proved reserves which it is believed can be developed through the extensions and new pool discoveries which will be made in association with fields which have already been discovered. The Committee estimates a total resource in this category of 192 Tcf and believes that the degree of uncertainty surrounding this estimate is relatively small.

The second category of resources are Possible resources, and these represent the Committee's estimate of the resource which can be discovered through new field discoveries in geologic provinces and in formations in which previous natural gas production has already been established. This is essentially the extension of known producing trends. The Committee's most likely estimate of this resource potential is 355 trillion cubic feet. This does not represent the maximum potential but rather a discounted, conservative estimate based on the evaluation of the resource potential and the probability of existence of recoverable accumulations.

The third category of resource is Speculative resources and these estimates represent the Committee's best judgment as to the potential for natural gas development in frontier basins and in the deeper parts of currently producing basins where there are formations which are potentially productive but have not yet been demonstrated to be actually productive. The evaluation of most frontier basins and nonproducing formations is based on comparisons of the characteristics of these areas with known producing areas. There is considerable uncertainty regarding the exact magnitude of this resource potential but the Committee's most likely estimate is 329 trillion cubic feet. Again it is likely that this is a conservative estimate because it has been strongly discounted for the probability of actual existence of the accumulations.

The general distribution of the estimated resource potential between the lower 48 states and Alaska, onshore and offshore, is given in the following table:

Table 1--Estimated potential supply of natural gas (trillions of cubic feet at 14.73 psia and 60° F.)

	Probable	Possible	Speculative
Lower 48 States			
—Onshore	151	263	179
—Offshore	33	63	53
Alaska			
—Onshore	6	16	28
—Offshore	2	13	69
Total United States	192	355	329

Figure 1 is a map of the reporting areas used by the Potential Gas Committee and table 2 lists the estimates for each of these reporting areas for each of the resource categories and divided into onshore and offshore resources.

Of the total resource potential, 48%, or approximately 420 Tcf, is estimated to occur in the lower 48 states at drilling depths less than 15,000 feet or in offshore water depths less than 200 meters (656 feet). These potential resources are judged to be relatively accessible and to be amenable to future discovery and development with relatively moderate cost. Gas resources occurring in the lower 48 states at drilling depths greater than 15,000 feet are estimated to be 274 Tcf or 31% of the total. Similarly, 48 Tcf, or 5%, is estimated to occur beneath offshore water depths of 200 to 1,000 meters (3,280 feet). Alaskan potential is estimated to be 134 Tcf, or 15%, of the total. The resources which are estimated to exist at depths below 15,000 feet, below deep water offshore, and in Alaska will be relatively more difficult to find and produce and, consequently, will involve higher costs of exploration and development. The resources which are relatively difficult to develop total approximately 52% of the total resource potential.

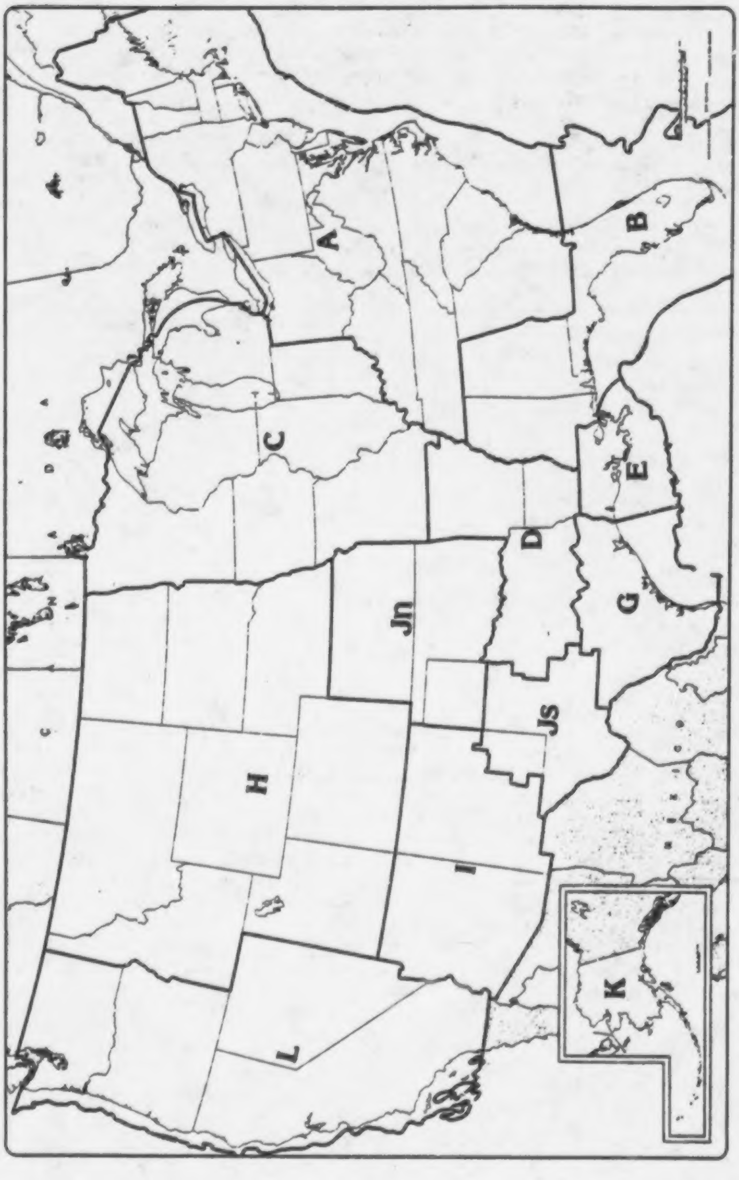
A
B
C
D
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Figure 1 — Reporting areas—Potential Gas Committee

Table 2 — Estimated potential supply of natural gas in United States by geographic areas as of December 31, 1982
(trillions of cubic feet at 14.73 psia and 60° F.)

Area		Probable	Possible	Speculative
A	Onshore	27	8	33
	Offshore	—*	—	16
B	Onshore	6	6	7
	Offshore	1	2	28
C	Onshore	—	2	1
D	Onshore	8	20	19
E	Onshore	6	15	—
	Offshore	21	36	—
G	Onshore	12	15	4
	Offshore	11	16	—
H	Onshore	49	93	66
I	Onshore	2	3	1
J-North	Onshore	24	60	39
J-South	Onshore	15	33	1
L	Onshore	2	8	8
	Offshore	—	9	9
	48 States Subtotal	184	326	232
K	Alaska - Onshore	6	16	28
	- Offshore	2	13	69
	Total United States	192	355	329

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*In all tables, dashes are used to represent estimates of potential of less than 0.5 Tcf.

Viewed from a closer perspective, the national total estimate is a combination of regional estimates and these regional estimates have individually been increased and decreased as new information and experience has been gained in the process of exploration and drilling. Table 3 summarizes the changes in area estimates for the most recent four estimates of the Potential Gas Committee. Frontier areas, such as Alaska and portions of the Rocky Mountain states, tend to have major changes because the exploratory plays are in the early stages of development, while other areas have been more stable. The 1982 estimate for the Rocky Mountain states was increased largely because of inclusion of quantities of low-heat-content gas in western Wyoming. This gas is now believed to be a viable resource because the carbon dioxide contained with the methane also has a market value because of its use in secondary recovery of oil. Additional potential has also been added to the estimate for the Rocky Mountain states because some areas in central Wyoming have now been shown to have sedimentary rocks existing beneath major faults. These sub-thrust sedimentary rocks provide additional targets for exploration. The increases in the Rocky Mountain states partly offset decreases in estimates for other states. Prior to 1982, the estimate for the Rocky Mountains had been increased substantially (in 1978) for the important new exploration concepts which were being developed at that time in the Western Overthrust Belt.

The estimate of potential for the Mid-Continent area (Area J-North), particularly Oklahoma, was decreased due to transfers in potential resources to proved reserves. This is a normal development as the industry discovers and produces the resources initially estimated by the Potential Gas Committee. Additionally, the information derived from high levels of drilling activity in recent years in Oklahoma has enabled members of the Committee to make a better evaluation of the resource potential. The exploration drilling activity confirmed some estimates made previously but, also, resulted in some disappointments, such as in the deep Pennsylvanian Springer sands in the southeastern part of the Anadarko basin. The estimate for California, Oregon, Washington and Nevada (Area L) was reduced in the 1982 estimate primarily because of a re-evaluation of the potential of the San Joaquin basin plus normal transfers to proved reserves and production. Recent seismic work and wildcat drilling have diminished what had been considered to be prospective acreage in Alaska (Area K), for example, portions of the Arctic basin, the Gulf of Alaska, the Lower Cook Inlet and the Kodiak area.

Estimates prepared in 1982 for other areas of the country showed no significant changes from previous years other than those expected by normal developments. These include the relatively mature exploration and production areas of Texas (Areas D, G and J-South) and Louisiana (Area E), which have shown consistent declines in estimates of future gas potential as their gas resources have been developed and produced.

It is important to bear in mind that changes in resource estimates are an expected result of the normal progress of gas exploration and development. As new discoveries are made or, unfortunately, dry holes are drilled, new information is gained which modifies previous concepts. The overall trend of resource estimates should be downward as new discoveries are made. Occasional upward revisions are the result of welcome surprises.

Table 3 — Estimated potential supply of natural gas
in the United States by geographic areas
(trillions of cubic feet at 14.73 psia and 60° F.)

Area	1976	1978	1980	1982
A	102	121(+19)	86(−35)	84(− 2)
B	51	53(+ 2)	54(+ 1)	50(− 4)
C	6	4(− 2)	3(− 1)	3
D	54	50(− 4)	51(+ 1)	47(− 4)
E	118	98(−20)	81(−17)	78(− 3)
G	93	85(− 8)	69(−16)	58(−11)
H	64	160(+96)	187(+27)	208(+21)
I	7	6(− 1)	6	6
J-North	107-157	143	135(− 8)	123(−12)
J-South	56	53(− 3)	51(− 2)	49(− 2)
K	225	189(−36)	145(−44)	134(−11)
L	40	57(+17)	45(−12)	36(− 9)
	923-973	1019(+60)	913(−105)	876(−37)

There are some significant consequences to the geographic distribution of the resource potential as estimated by the Potential Gas Committee. One of these is the shift in location of the potential resource in the Speculative category as compared to the Probable and Possible. The traditional area of large reserves and production for the United States has been the Gulf Coast area, Permian basin, the Mid-Continent region and the Ark-La-Tex area of east Texas, north Louisiana and Arkansas (Potential Gas Committee Areas D, E, G, J-North and J-South). Most of the resource potential for the Gulf Coast region and the Permian basin is in the Probable and Possible categories, with little in the Speculative category. The Ark-La-Tex and Mid-Continent areas still have considerable potential in the Speculative category. Other areas in the lower 48 states with considerable potential in the Speculative category include the Rocky Mountains (Area H) and the Appalachian region (Area A).

This resource distribution through the three categories can be viewed as representing, in a general way, the gradual shift of exploratory and development activities through the years into those areas in which the Speculative potential lies. This will reflect a gradual depletion of the Probable and Possible resources and development of the Speculative. It is also anticipated that this will become an increasingly apparent factor in the remaining years of this century and into the 21st century as the focus of exploration moves more and more into the Rocky Mountain region and portions of the Appalachian basin in addition to the Mid-Continent area of Oklahoma.

As more and more of the new fields being developed occur away from the Gulf Coast region, there will be a decline in deliverability of gas on a daily or annual basis. To illustrate, let us compare the Gulf Coast area with the Rocky Mountain and Appalachian regions. The reserves-to-production ratio, or reserve life index, for fields in the offshore area of the Gulf of Mexico has been approximately 8, meaning that essentially one-eighth of the remaining reserve from a field is produced each year. In the Rocky Mountain region, the comparable number is approximately 13, and in the Appalachian region, it is approximately 16. Applying these numbers to a typical field production history, it would mean that almost 50% of the total reserve in a field is produced within the first five years in the offshore Gulf of Mexico, even more in some cases in recent years, while only 33% of the total reserve would be produced in the first five years from a Rocky Mountain field, on the average, and about 28% from an Appalachian field.

The significance of the figures in reserve life index is that the characteristics of the reservoirs in the Gulf Coast permit the gas to be extracted at a much more rapid rate than in the other two areas. In order to maintain the daily level of productivity in the Rocky Mountain or Appalachian area as compared to present Gulf Coast production, it will be necessary to complete more wells in more fields. The necessity, through time, to complete more wells and more fields in order to maintain a daily rate of production will require increased levels of exploration and drilling activity, and will result in a higher unit cost for the gas. These factors contribute to the conclusion reached by a number of studies that the quantity of gas on a daily basis which will be available in the latter part of the 20th century will be less than the current availability.

The Potential Gas Committee believes that it has made a credible evaluation of the national resource potential based on the conscientious work of experienced and knowledgeable persons who are actively engaged in natural gas exploration and development. My job has been to oversee the scientific and professional work which has gone into preparing the estimates and to verify that, insofar as the data will permit, accepted procedures have been used in preparing the resource estimate. We believe that the credibility of the Potential Gas Committee estimates are strengthened by the independent work of the Resource Appraisal Group of the United States Geological Survey. An estimate prepared by the Resource Appraisal Group at about the same time as the last estimate of the Potential Gas Committee (U.S.G.S. Circular 860) gives a mean estimate of the U.S. natural gas potential as 771 trillion cubic feet. Considering the uncertainty involved in estimating unknown and undiscovered quantities of the resource, we believe that this is a very comparable estimate.

Lower estimates have been prepared and published by other organizations, notably in recent years Richard Nehring and colleagues of The Rand Corporation and Dr. M. King Hubbert. Mr. Nehring's projection is based on analysis of large fields discovered in the past and an evaluation of the large fields which remain to be discovered. Dr. Hubbert's evaluation is based on the projection of historic discovery rates. The Potential Gas Committee believes that the difference between the results of studies such as these and the work of the Potential Gas Committee and the U.S. Geological Survey lies in the ability of the exploration geologist to visualize potential prospects which are not reflected in the historical statistics.

Members of the Potential Gas Committee are decidedly optimistic about the future resources of natural gas which exist in this country. They believe that their estimates, based on the data available to them at the time of compilation, present a reasonable picture of the resource base. They also believe that this resource base will provide a foundation of continued adequate supplies of natural gas to meet the energy needs of the Nation well into the 21st century.

UNCONVENTIONAL RESOURCES

The Potential Gas Committee does not include in its estimates those resources which are believed to exist in accumulations which are beyond reasonable economic limits or which will require unproved technology to develop. The economic limits imposed by the Committee on its estimates involve a test of the relationship between cost of development and the price which can be obtained for the produced gas which is sufficient to provide economic incentive for the development of the gas. The economic aspects of this question will be discussed in the next section. The technological limits imposed by the Committee are that the technology for recovery of the gas is either current or foreseeable. This would preclude resources which exist under conditions which will require radical new developments in technology.

In applying the technological, and to a lesser extent economic, limits to its resource estimates, the Potential Gas Committee has included in its estimates quantities of natural gas which might be recovered from low permeability formations, such as Western tight gas sands and Devonian shales. The economic and technical viability of some of these resources has been demonstrated through current production.

In some studies, such as that released by the National Petroleum Council in December 1980, resources which are believed to exist in low-permeability Western tight gas sands and in Devonian shales were included under the category of unconventional resources. The National Petroleum Council study included in the category of Tight Gas Sands, resources in formations with permeabilities as high as 1 millidarcy, although most of the resource was contained in formations with in-situ permeabilities to natural gas of less than 0.1 millidarcy. With the coming of age of improved completion technology for tight (low permeability) formations along with some price incentives, some of this formerly "unconventional" gas resource is rapidly increasing in importance as a "conventional" resource. The boundary of what is considered conventional has gradually shifted into some resources which were previously considered as unconventional. Because the Potential Gas Committee believes that the viability of some of these resources has been demonstrated, it has included in its estimates all of the resource in these categories which falls within the Committee's limits of economics and technology.

A review of all areas where the Potential Gas Committee now estimates conventional natural gas potential indicates that as much as 20% of its total potential resource estimate, or 172 Tcf, may occur in low permeability formations. A summary is included as table 4. These quantities have been incorporated gradually, over a number of years, into the Committee's estimates. It is our evaluation that perhaps 50% of these resources have also been included in estimates such as those of the National Petroleum Council. Because of overlaps such as this, caution must be exercised in comparing the results of studies by different organizations covering different portions of the natural gas resource.

COST OF NATURAL GAS DEVELOPMENT

Questions regarding the economic development of the natural gas resource group into two major categories: (1) Is the resource potential economically viable in relation to the anticipated price and demand for natural gas, and (2) what is the relative difference in the cost of development of the resource potential from area to area and from depth to depth as well as in comparison to the resource available in other forms, such as imports from Canada or Mexico, LNG imports, or coal gasification? In an attempt to answer some of these questions, the Mineral Resources Institute at Colorado School of Mines has undertaken an investigation of the cost of development of the resource potential estimated by the Potential Gas Committee.

Table 4 — Potential natural gas resources in tight formations

Estimated percentage of natural gas potential occurring in formations
with less than 0.1 millidarcy relative permeability to gas

	PROBABLE				POSSIBLE				SPECULATIVE			
	0 - 15,000 ft.		15,000 - 30,000 ft.		0 - 15,000 ft.		15,000 - 30,000 ft.		0 - 15,000 ft.		15,000 - 30,000 ft.	
AREA - Onshore	Total Potential (Tcf)	Amount in Tight Fms. (%)	Total Potential (Tcf)	Amount in Tight Fms. (%)	Total Potential (Tcf)	Amount in Tight Fms. (%)	Total Potential (Tcf)	Amount in Tight Fms. (%)	Total Potential (Tcf)	Amount in Tight Fms. (%)	Total Potential (Tcf)	Amount in Tight Fms. (%)
A	27	87%	—	—	8	5%	—	—	22	—	11	—
B	4	8%	2	9%	3	8%	3	10%	3	10%	4	12%
C	—	—	—	—	2	—	—	—	1	—	—	—
D	8	10%	—	—	20	15%	—	—	15	20%	4	20%
E	3	—	3	—	4	—	11	—	—	—	—	—
G	7	4%	5	6%	9	6%	6	8%	2	6%	2	8%
H	29	75%	20	25%	57	39%	56	26%	26	27%	40	73%
I	2	47%	—	—	3	11%	—	—	1	—	—	—
J-North	15	—	9	22%	22	5%	38	37%	5	60%	34	59%
J-South	7	7%	8	—	19	2%	14	—	1	—	—	—
L	1	4%	1	30%	6	5%	2	30%	7	10%	1	40%
Total Onshore Lower 48 States	151 Tcf 37%				263 Tcf 19%				179 Tcf 36%			

In consultation with the Committee members, we have postulated a resource distribution by geologic province and by depth as well as a postulated distribution of sizes of undiscovered natural gas accumulations. To this resource distribution, we have applied cost estimates based on historic drilling costs and anticipated costs in the industry, and have also taken into account the costs of geological and geophysical exploration, lease costs, royalties, taxes, overhead and return on investment.

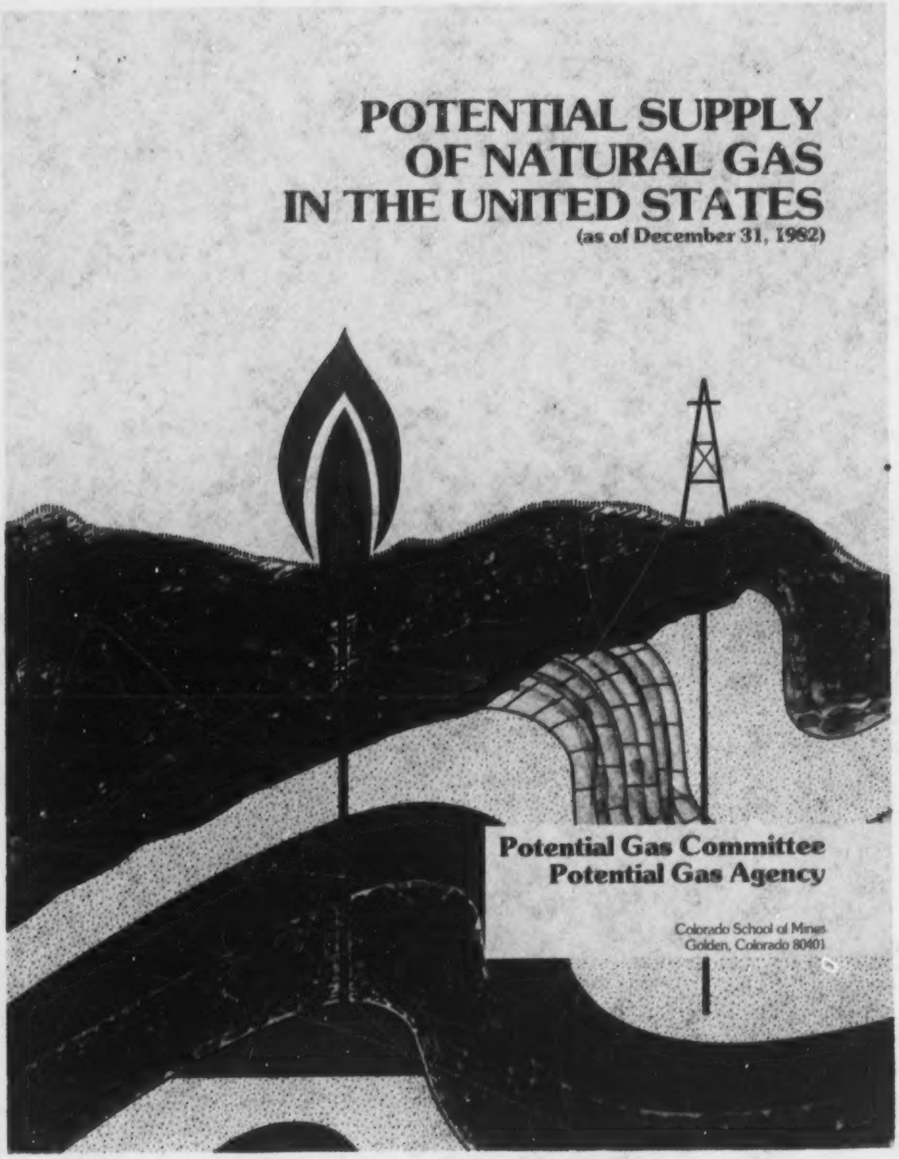
We are in the final stages of accumulation of the resource data and cost data. We have also developed the economic model for analysis of these data and have completed the first preliminary analyses for two geologic provinces, the Permian basin of west Texas and eastern New Mexico, and the Interior Salt basin of Mississippi and Alabama. Basically, our results indicate that the potential of 37 Tcf of nonassociated gas in the Permian basin could be developed at an average cost of $3.63 per Mcf in constant 1980 dollars. The potential resource of 13.6 Tcf of nonassociated gas in the Mississippi-Alabama Interior Salt basin could be developed at an average cost of $4.12 per Mcf in constant 1980 dollars. These preliminary results apply only to these two basins.

Preliminary indications are that the vast majority of the gas resources estimated to exist in the onshore areas and the Continental Shelf areas of the lower 48 states can be developed at reasonable cost. Reasonable cost, however, implies that there will be increases in price related to the increased difficulty and expense of recovery of some of this gas, the deeper and more remote resources, and that there will be a sufficient demand for the product to justify continued exploration and development.

Increasing costs will be incurred in the development of smaller fields, especially at greater depths and in the more uncertain Speculative category. Marginal costs of resource development have been estimated on the assumption that the largest fields will be discovered and developed first and the smallest fields last. Marginal costs for development of the Permian basin nonassociated gas resource range from $1.08/Mcf to $32.47/Mcf (1980 constant dollars). Seventy-seven percent of the resource potential has an estimated marginal cost of less than $5.00/Mcf and 97% has an estimated marginal cost of less than $10.00/Mcf. In the Interior Salt basin, the marginal costs range from $0.38/Mcf to $112.26/Mcf (1980 constant dollars). Seventy-nine percent of the resource potential has an estimated marginal cost of less than $5.00/Mcf and 97% has an estimated marginal cost of less than $10.00/Mcf. Thus, although some of the resource will be relatively expensive to find and develop, the bulk will be attainable at moderate increases above current costs. In actual experience, we believe that the costs of development will be closer to average than to marginal costs because the smaller fields will be discovered during the entire exploration process rather than concentrated in the last stages.

CONCLUSIONS

The work of the Potential Gas Committee indicates that there is a considerable resource potential which is still accessible for exploration and development in the United States, including both the lower 48 states and Alaska. This undeveloped resource potential is approximately equal in magnitude to the total cumulative production in the history of the United States industry plus the present proved reserves. Including the present proved reserves, some 60% of the original potential still remains to be produced. Further, a sizable portion of this resource potential exists in areas which are relatively accessible and relatively inexpensive to develop, namely drilling depths less than 15,000 feet in onshore areas and in water depths of less than 200 meters in offshore areas. Preliminary results of economic evaluations also indicate that much of this resource potential will be accessible at costs which are consistent with current economics.



POTENTIAL SUPPLY OF NATURAL GAS IN THE UNITED STATES

(as of December 31, 1982)

Potential Gas Committee
Potential Gas Agency

Colorado School of Mines
Golden, Colorado 80401

The Potential Gas Committee comprises volunteer members from the natural gas industry, government agencies, and academic institutions who are concerned with natural gas resources.

The Committee functions independently but with the guidance and assistance of the Potential Gas Agency of the Colorado School of Mines. The Potential Gas Agency is supported by the American Gas Association.

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POTENTIAL SUPPLY OF NATURAL GAS IN THE UNITED STATES

(as of December 31, 1982)

Report of the Potential Gas Committee
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Report of the Potential Gas Agency
Harry C. Kent, Director
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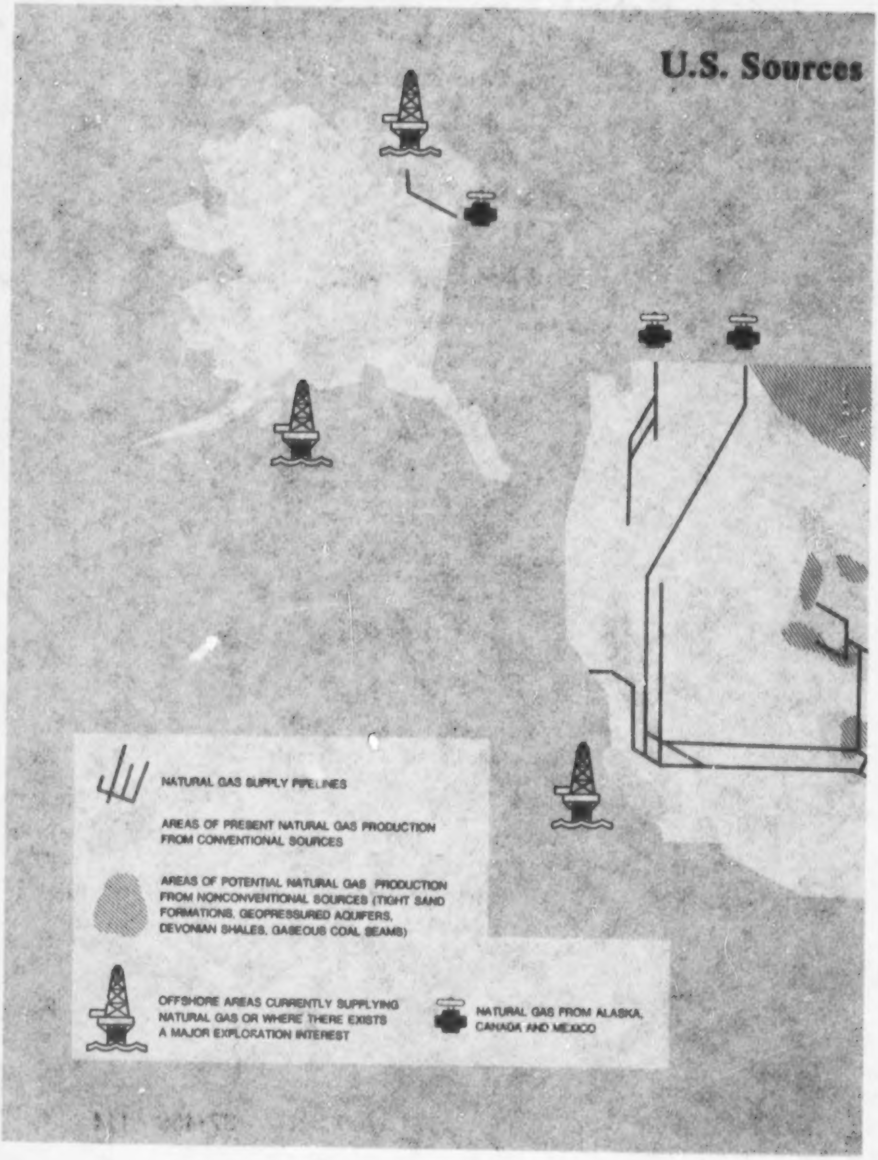
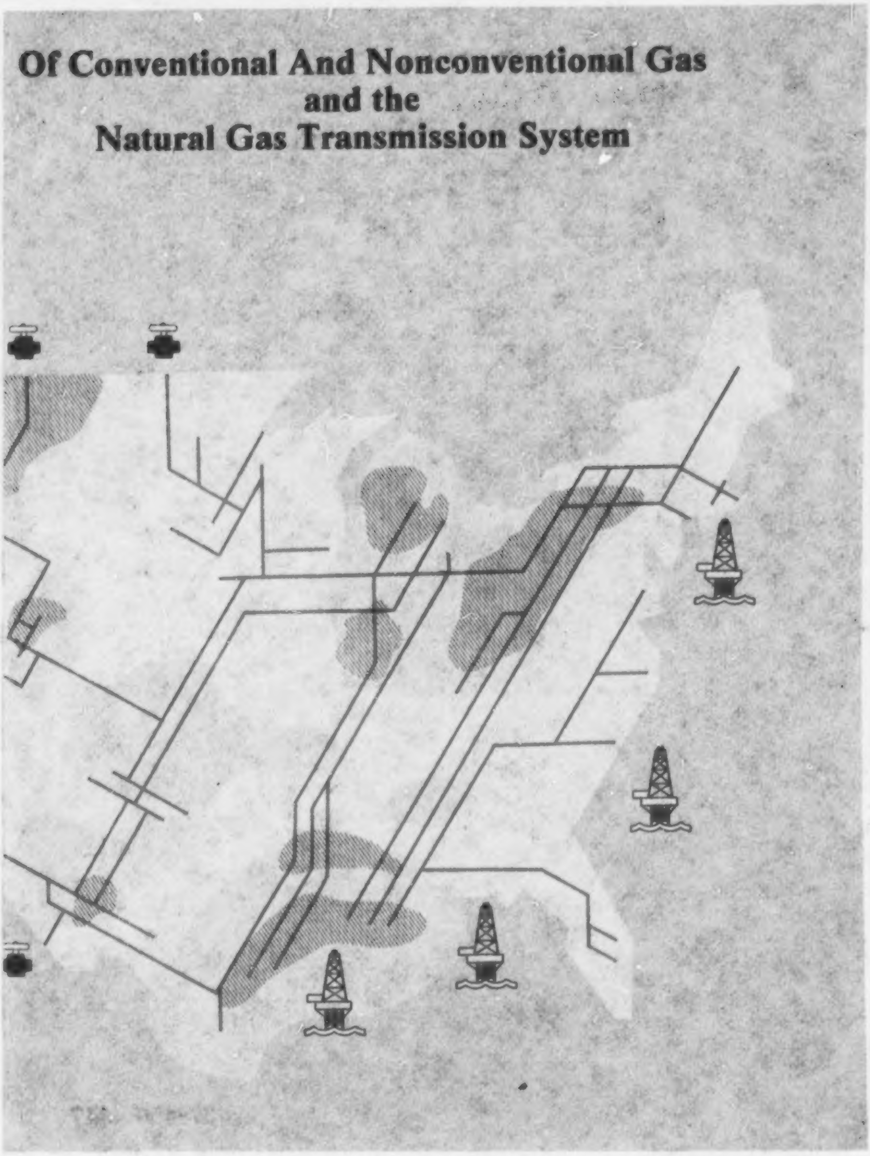
Potential Gas Agency
Colorado School of Mines

June 1983


U.S. Sources
NATURAL GAS SUPPLY PIPELINES
AREAS OF PRESENT NATURAL GAS PRODUCTION FROM CONVENTIONAL SOURCES
AREAS OF POTENTIAL NATURAL GAS PRODUCTION FROM NONCONVENTIONAL SOURCES (TIGHT SAND FORMATIONS, GEOPRESSURED AQUIFERS, DEVONIAN SHALES, GASEOUS COAL SEAMS)
OFFSHORE AREAS CURRENTLY SUPPLYING NATURAL GAS OR WHERE THERE EXISTS A MAJOR EXPLORATION INTEREST
NATURAL GAS FROM ALASKA, CANADA AND MEXICO

Of Conventional And Nonconventional Gas and the Natural Gas Transmission System



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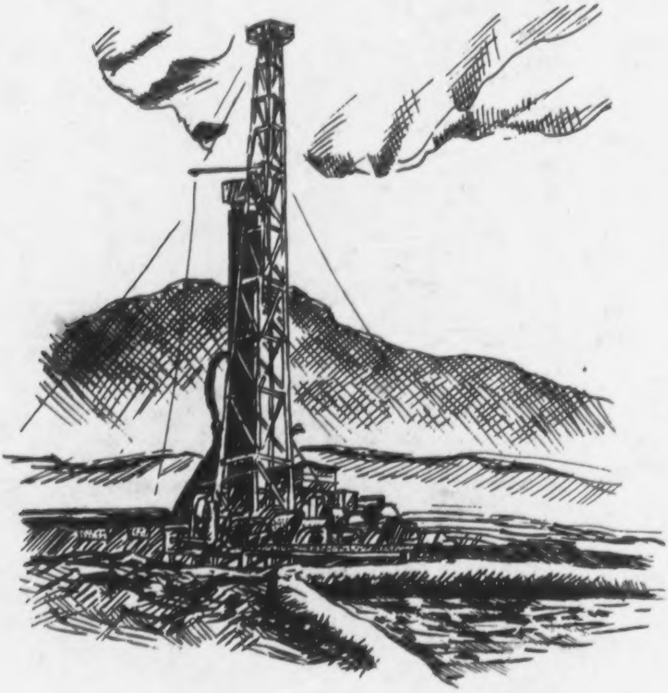
PART I

REPORT OF THE POTENTIAL GAS COMMITTEE



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REPORT OF THE POTENTIAL GAS COMMITTEE

Summary

The Potential Gas Committee comprises volunteer members from the natural gas industry, government agencies, and academic institutions who are concerned with natural gas resources. Members of the Committee, their experience and affiliations, are listed in Part III of this report. The Committee functions independently but with the guidance and assistance of the Potential Gas Agency of the Colorado School of Mines. The Potential Gas Agency is supported by the American Gas Association. Biennial estimates of the potential supply of natural gas have been prepared and published since 1966, with the exception of 1974.

The Potential Gas Committee's estimate of the potential supply of natural gas in the United States, as of December 31, 1982, is as follows:

Table 1 — Estimated potential supply of natural gas (trillions of cubic feet at 14.73 psia and 60° F.)

	Probable	Possible	Speculative
Lower 48 States			
—Onshore	151	263	179
—Offshore	33	63	53
Alaska			
—Onshore	6	16	28
—Offshore	2	13	69
Total United States	192	355	329

The sum of these estimates represents a total resource potential of 876 trillion cubic feet (Tcf).

The foregoing estimates represent the conventional potential supply expected to be recovered by future drilling under conditions of:

1. adequate economic incentives in terms of price/cost relationships, and
2. current or foreseeable technology.

These estimates do not assume any fixed time schedule for the discovery and production of future gas supply.

The Potential Gas Committee's estimates do not include, and are distinct and separate from, the volume of proved recoverable natural gas reserves estimated by the Committee on Natural Gas Reserves of the American Gas Association through 1979 and by the Office of the Oil and Gas Information System, Energy Information Administration, U.S. Department of Energy, since 1977. The relationship betwen proved reserves and the several categories of potential natural gas supply is illustrated in figures 2 and 3, and described in detail in the section entitled "Categories of Natural Gas Resources."

The Potential Gas Committee's previously published estimates of each category, as of December 31, 1980, of the potential supply of natural gas in the United States were as follows (trillions of cubic feet): Probable 193, Possible 358, and Speculative 362.

Comparison of these totals with the new estimates presented in table 1 reveals little change in the Probable and Possible categories and a decrease of 33 trillion cubic feet in the Speculative category. These estimates, however, represent the current status of a dynamic system in which former potential resources pass into proved reserves and production through discovery and development of new pools and fields and the estimates of remaining potential resources are revised based on knowledge gained through additional exploration and drilling.

Frontier areas, such as some offshore regions, Alaska, and portions of the Rocky Mountain states, tend to have major changes in resource estimates from report to report, especially in the Speculative category. These changes reflect the uncertainty of resource estimation where available geological and geophysical data are limited and where new exploration programs may bring about significant changes in the knowledge and interpretation of the nature and occurrence of the natural gas resource.

The current estimate for the Rocky Mountain states (Area H) has been increased over 1980 largely because of the inclusion of large quantities of low-heat-content gas in western Wyoming and of potential now believed to exist in some areas in central Wyoming where gas-bearing sedimentary rocks are now known to occur beneath major thrust faults. It is now believed that the low-heat-content gas can be commercially developed and that the sub-thrust sedimentary rocks provide additional targets for exploration.

The estimate of potential for the Mid-Continent area (Area J-North), particularly Oklahoma, was decreased due to transfers from potential resources to proved reserves and to better evaluation of the potential made possible by recent high levels of drilling activity. This activity confirmed some estimates made previously but there have been disappointments also in some areas such as the deep Pennsylvanian Springer sands in the southeastern part of the Anadarko basin. The estimate for California, Oregon, Washington and Nevada (Area L) has been reduced primarily because of a re-evaluation of the potential for the deep portion of the San Joaquin basin plus transfers to proved reserves. Recent exploration activity has diminished what had been considered to be prospective acreage and potential resources in Alaska (Area K), for example, portions of the Arctic basin, the Gulf of Alaska, the Lower Cook Inlet, the Kodiak and Yakataga areas and the Bering Sea.

Estimates for the other areas of the country show no significant changes other than those expected by normal developments. These include the relatively mature exploration and production areas of Texas (Areas D, G, and J-South) and Louisiana (Area E) which have shown consistent declines in estimates of potential gas resources as their gas resources have been discovered and developed.

Introduction

The objective of the Potential Gas Committee is to provide estimates, based upon expert knowledge, of the potential supply of natural gas which, in conjunction with estimates of proved reserves of natural gas, make possible an appraisal of long-range gas supply.

For many years, estimates of future supply of natural gas have been developed by numerous individuals and organizations. Since these estimates of future supply have varied widely and often have had entirely different objectives and meanings, they have served to confuse rather than to clarify the long-range outlook for natural gas supply. With the view to achieving a more unified industry-sponsored effort, many of the leaders of the natural gas industry, as well as various financial and governmental agencies, expressed a strong desire for a continuous long-range study of the requirements and supply of natural gas in the United States. As a result of this concern, the work of the Potential Gas Committee was initiated in 1960. The Committee has continued to function since that time and has prepared regular reports presenting estimates of the recoverable natural gas which is believed to exist in addition to that amount included in proved reserves. Since 1967 the work of the Committee has been guided and assisted by the Potential Gas Agency of the Colorado School of Mines.

Annual estimates of proved reserves of natural gas in the United States were prepared, through 1979, by the Committee on Natural Gas Reserves of the American Gas Association. Since 1977, and continuing to the present, annual estimates of proved reserves have been prepared independently by the Energy Information Administration of the U.S. Department of Energy. These estimates are, by definition, limited to those estimated proved recoverable reserves of natural gas which have been established by drilling. Such estimates do not reflect potential supplies of natural gas which may be discovered as a result of future exploratory drilling. It is the estimates of future supply which are the concern of the Potential Gas Committee and which are discussed in this report.

The estimates of the Potential Gas Committee include recoverable "conventional" natural gas which, in the judgment of Committee members, can be recovered given adequate economic incentives in terms of price/cost relationships and utilizing current or foreseeable technology. Since these potential resources have not yet been confirmed by drilling and testing, there can be no rigorous evaluation of the economic viability of the resources, but the accumulations are believed to exist in concentrations which are of sufficient size and quality, considering geographic distribution and depth of occurrence, to warrant exploration and development.

Previous volumes (1978 and 1980) have included summaries, prepared by the Potential Gas Agency, of estimates of potential resources of natural gas which may exist under nonconventional conditions, including gas from tight formations, Devonian shales, geopressured brines, coal beds, and gas hydrates. A similar summary is not included with this report and the reader is referred to the previous publications for such information.

Review of the estimates of the Potential Gas Committee has indicated that a portion of the natural gas resource estimated by the Committee is believed to occur in formations which have **in situ** permeabilities to natural gas of less than 0.1 millidarcy. Such resources have been included by others in estimates of nonconventional resources and, consequently, there is partial overlap with estimates of the Potential Gas Committee. The magnitude of this overlap is addressed in the reports of the Area Work Committees included in this volume.

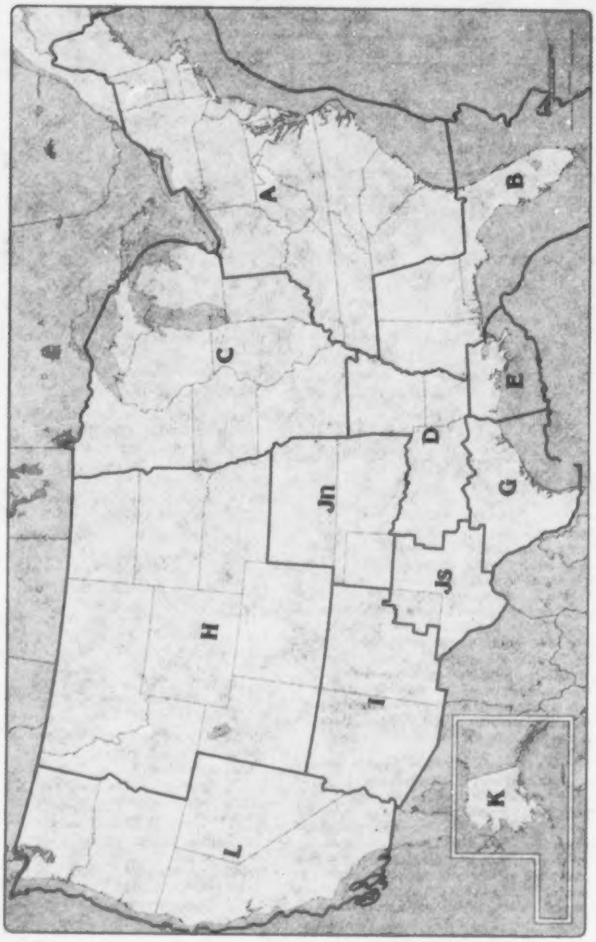
A
B
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Figure 1 — Reporting areas—Potential Gas Committee

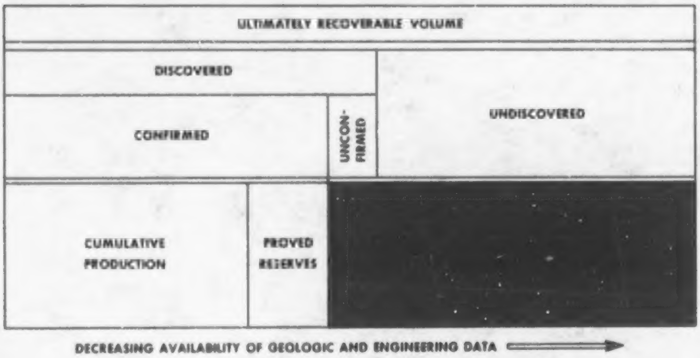
ULTIMATELY RECOVERABLE VOLUME
DISCOVERED
CONFIRMED
UNCON-FIRMED
UNDISCOVERED
CUMULATIVE PRODUCTION
PROVED RESERVES
DECREASING AVAILABILITY OF GEOLOGIC AND ENGINEERING DATA

Figure 2 — Categories of past, present and future natural gas supplies

Categories of Natural Gas Resources

The estimates of potential supply of natural gas presented in this report can be used responsibly only with a thorough understanding of how they are defined and what they represent. An overlying constraint on estimating the amount of any natural resource is what is known about it. Unlike some other resources, natural gas is unseen and very diffuse. Accumulations are found in porous rocks buried beneath the surface of the earth in a wide variety of structural and stratigraphic traps. Such characteristics make precise estimates difficult to calculate without a large amount of data. Since the data base is never as complete as one may wish, estimates are dependent upon the professional judgment of the estimator and his continuing analysis as new data become available.

In order to be able to report reliable and meaningful estimates, the Potential Gas Committee has adopted a number of supply or resource categories. To ensure credibility, the categories are established on the basis of specific criteria. Much of what is known about natural gas accumulation is based on geological principles. It is, therefore, reasonable to utilize this type of knowledge and the availability of this knowledge as a basis for defining specific categories. The categories of natural gas resources used by the Potential Gas Committee are shown in figure 2 and are defined and discussed in the following section. A schematic representation of the various categories of potential supply is illustrated in figure 3.

Explanation for Figure 3 — Schematic representation of categories of potential supply

I Probable — Associated with existing fields — most assured,
  1) Discovered: discovered trap, existing production [1]
  2) Undiscovered: undiscovered trap, productive formation — supply from new pool discoveries within existing fields in
    a) reservoir producing within the same field [2]
    b) shallower or deeper formations producing elsewhere within same geologic province or subprovince [3]

II Possible — Associated with productive formations — less assured,
  1) Similar geologic conditions [4]
  2) Different geologic conditions: e.g., stratigraphic vs. structural trap [5]

III Speculative — Most nebulous
  1) From nonproductive formations in productive province
    a) new pool [6]
    b) new field [7]
  2) From nonproductive province [8]

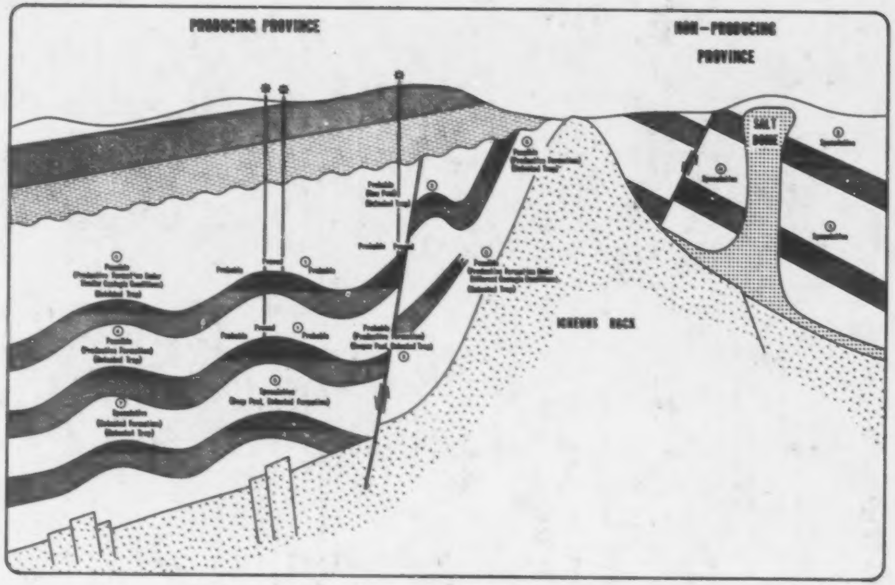
PRODUCING PROVINCE
NON-PRODUCING PROVINCE
Probable
Proved
Probable
Proved
Possible
Speculative
SALT DOME
IGNEOUS ROCK

Figure 3 — Schematic representation of categories of potential supply

DEFINITION OF NATURAL GAS

Natural gas, as used in this report, is any gas (at standard conditions of temperature and pressure) of natural origin that is composed primarily of hydrocarbon molecules producible from a borehole. Most natural gas contains some nonhydrocarbon components such as carbon dioxide, nitrogen, hydrogen sulfide, helium, etc. In estimating potential supply, it is not feasible to separate small volumes of these components from the hydrocarbons; however, in areas where significant volumes of such nonhydrocarbons are believed to occur, only the hydrocarbon components are included in the estimated potential supply.

NATURAL GAS RESOURCES

At a given time a finite volume of natural gas in-place exists within the rocks of the shallow portion of the earth's crust. This finite volume of gas in-place is the total natural gas resource. The amount of this resource which is recoverable is a function of technology and economics. Today, technology has advanced to the degree that a significant part of the resource base can be recovered. A major part of this resource, however, is dispersed throughout the earth's crust in such minute accumulations or under such conditions that it cannot be extracted with existing or foreseeable technology, and also because the cost of recovery of this gas is too high compared to the value of the gas. Even with likely advances in technology, production of some deposits will not be feasible because recovery of such accumulations would require more energy than that provided by the gas produced.

Estimates of the Potential Gas Committee include only the natural gas resource which can be discovered and produced using current or foreseeable technology and under the condition that the price/cost ratio will be favorable. This total quantity is referred to as the *Ultimately Recoverable Volume*. Terminology used in this report emphasizes that the Committee is presenting estimates of natural gas which they believe can be both *discovered* and *recovered* under the limiting conditions established by the Committee.

The *Ultimately Recoverable Volume* represents the quantity of natural gas expected to be produced during the life of the industry through exploration and development of the resource. Recovery would be effected by utilizing conventional techniques of exploration, drilling, completion and production and also by incorporating new technological developments. The Ultimately Recoverable Volume is composed of both the *discovered* and the *undiscovered* natural gas resources. Discovered gas consists of the quantity which has been produced in past years plus that which has been proved by drilling and engineering tests and is included in present *Proved Reserves*. Additionally, discovered gas includes the gas, remaining in known fields, which will be recovered through extension and complete development of known pools and reservoirs. The undiscovered resource consists of the potential gas supply which is expected to become productive upon further exploration and development and includes both the gas remaining in undiscovered pools and reservoirs within known fields and the gas which may be discovered in new fields and reservoirs within provinces which are presently productive and within provinces which are as yet unproductive.

The subdivision of Ultimately Recoverable Volume into categories reflects the variation in the amount of geological and engineering information upon which the estimate is based. Proceeding from left to right in figure 2, the level of geological and engineering knowledge decreases.

Past production is reported as cumulative production and is the total volume of natural gas withdrawn from producing reservoirs. Some uncertainty involving the amount of production from earlier years exists as a result of incomplete records, but a reasonable estimate has been made based on available information. Estimates of past production presented in this report have been prepared by the Committee on Natural Gas Reserves of the American Gas Association.

Proved reserves are the currently estimated quantity of natural gas which analysis of geologic and engineering data demonstrate with reasonable certainty to be recoverable in the future from known oil and gas reservoirs under existing economic and operating conditions. Reservoirs are considered proved that have demonstrated the ability to produce by either actual production or conclusive formation tests. The existence and quantity of gas have been *confirmed* by testing. The Potential Gas Committee does not estimate volumes of proved reserves. Estimates of proved reserves were compiled annually from 1946 through 1979 by the Committee on Natural Gas Reserves of the American Gas Association (AGA). The AGA estimates have been largely supplanted by reports prepared by the Energy Information Administration of the U.S. Department of Energy (EIA). EIA reports of U.S. proved reserves began with data for 1977 and have replaced the AGA estimates for 1980 and subsequent years.

The *Potential* supply includes the remaining portion of discovered gas resource in addition to proved reserves and all of the undiscovered resource. Three categories of potential supply are recognized and reported by the

POTENTIAL GAS COMMITTEE	**PROBABLE**	**POSSIBLE**	**SPECULATIVE**
UNITED STATES GEOLOGICAL SURVEY RESOURCE APPRAISAL GROUP	**INFERRED RESERVES**	**UNDISCOVERED RECOVERABLE RESOURCES**	

Figure 4 — Comparison of Potential Gas Committee and U.S. Geological Survey natural gas resource classification categories

Potential Gas Committee: Probable, Possible and Speculative. These three categories are differentiated on the basis of variation in available geologic information. The reported figures are the estimate of the most likely amount of natural gas (i.e., modal value) that can be expected to be found and recovered in each category.

Probable potential gas supply is associated with existing fields. It is the most assured of potential supplies because it is associated with known accumulations and a relatively large amount of geological and engineering information is available to aid in estimation of the reported figures in this category. The Probable supply bridges the boundary between discovered and undiscovered resources. The discovered portion includes supply from future extensions of *existing pools* in known productive reservoirs [1].* The pool containing this gas has been discovered, but the extent of the pool has not been completely delineated by development drilling; therefore, the existence and quantity of gas in the undrilled portion of the pool are as yet *unconfirmed*. The undiscovered portion of Probable supply is expected to come from future *new pool* discoveries within existing fields either in reservoirs productive elsewhere in the field [2], or in shallower or deeper formations known to be productive elsewhere in the same geologic province or subprovince [3].

Possible potential supply is a less assured supply because it is postulated to exist outside of known fields, but it is associated with a productive formation in a productive province. Its occurrence is indicated by projection of plays or trends of a producing formation into a less-well-explored area of the same geologic province or subprovince. Supply is from *new field* discoveries, postulated to occur within these trends or plays under both similar [4] and different [5] geologic conditions (i.e., the types of traps and/or structural settings may either be the same or differ in some aspect).

Speculative potential gas supply is the most nebulous category. This potential supply is from formations or provinces which have not yet proven to be productive. Geologic analogs are developed in order to ensure reasonable evaluation of these unknown quantities. Supply is from *new pool* [6] or *new field* [7] discoveries in *formations not previously productive* within a productive geologic province or subprovince and also *new field* discoveries within a geologic *province not previously productive* [8].

To reiterate, the accuracy of the estimates of gas volumes included in the potential supply is dependent upon geological conditions and knowledge and the extent to which the given area has been explored and developed. By following the estimation guidelines as closely as possible, consistency and compatibility of the estimates by members of the Potential Gas Committee are maintained. However, the individual estimator may have to use slight modifications of the considerations and procedures when compiling estimates for each of the three categories because of the particular characteristics applicable to his reporting area.

Estimates of potential resources of natural gas in the United States are also made by the Resource Appraisal Group of the United States Geological Survey. Their most recent published report is contained in U.S.G.S. Circular 860[1] and includes estimates of crude oil and natural gas liquids as well as natural gas. Although resource terminology of the U.S.G.S. Resource Appraisal Group differs from that used by the Potential Gas Committee, the U.S.G.S. category Inferred Reserves is essentially equivalent to Probable resources, and the U.S.G.S. category Undiscovered Recoverable Resources is essentially equivalent to the combined Possible and Speculative categories (fig. 4). A further discussion of the definitions and usage of U.S.G.S. terminology is set forth in U.S.G.S. Circular 831.[2]

---

*Numbers in brackets refer to accumulations shown diagrammatically in figure 3.

[1] Dolton, G. L. and others, 1981, Estimates of undiscovered recoverable conventional resources of oil and gas in the United States: U.S. Geological Survey Circ. 860, 87 p.

[2] U.S. Bureau of Mines and the U.S. Geological Survey, 1980, Principles of a resource/reserve classification for minerals: U.S. Geological Survey Circ. 831, 5 p.

Estimation of Potential Gas Supply

TECHNIQUES FOR ESTIMATION OF POTENTIAL GAS SUPPLY

A basic technique for estimating potential gas supply is applied to each of the categories adopted by the Potential Gas Commitee. In each case, what is known about the prospective area is evaluated relative to what is known about natural gas accumulations and the factors known to control their occurrence. Studies of producing areas have provided information on the productive capacity of particular formations and the average size of accumulations. Natural gas occurrences are related to conditions which favor their formation and accumulation, such as the existence of source rocks, sufficient maturation of organic material, and presence of reservoir rocks and traps. Modification of the basic technique is necessary to accomodate the variations in amount of information available for prospective areas. In the most simplified form, the potential supply is derived by: (1) estimating the volume of potential gas-bearing reservoir rock, (2) multiplying this quantity by a yield factor,* and (3) discounting to allow for the probability that the traps and/or the accumulations exist. Figures 5-8 illustrate the modifications applied to this procedure for the different categories.

Probable potential supplies bridge the division between discovered and undiscovered resources. The discovered portion includes extensions of accumulations which are estimated to be partially developed. The undiscovered portion is composed of new pools which may be discovered within an existing field. In the case of *discovered*, but *unconfirmed*, *Probable* potential (fig. 5), the volume of potential rock is calculated to the limits of pool development based on geological, geophysical and engineering data. The estimated volume is multiplied by a yield factor obtained from the area of the field which is presently producing from the same formation as the extension being evaluated and which is adjusted for such possible variations as changes in lithology, thickness, porosity, permeability, hydrodynamic conditions or gas/oil/water relationships in the reservoir. To arrive at a *Probable* potential resource estimate, the product of the reservoir volume and the yield factor is then multiplied by the probability that the accumulation actually exists. This probability is determined by the estimator based on previous experience in development of similar fields in the province.

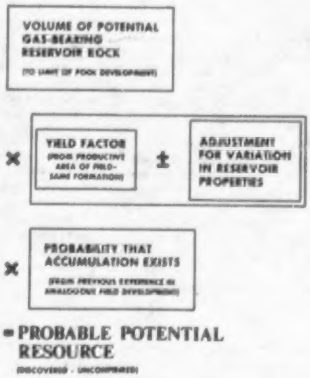
VOLUME OF POTENTIAL GAS-BEARING RESERVOIR ROCK
(TO LIMIT OF POOL DEVELOPMENT)
×
YIELD FACTOR
(FROM PRODUCTIVE AREA OF FIELD-SAME FORMATION)
±
ADJUSTMENT FOR VARIATION IN RESERVOIR PROPERTIES
×
PROBABILITY THAT ACCUMULATION EXISTS
(FROM PREVIOUS EXPERIENCE IN ANALOGOUS FIELD DEVELOPMENT)
= PROBABLE POTENTIAL RESOURCE
(DISCOVERED - UNCONFIRMED)

Figure 5 — Schematic diagram of procedure for estimation of discovered — unconfirmed Probable potential supply

Estimating *undiscovered Probable* potential supply (fig. 6) involves more geological and geophysical interpretation in order to delineate all possible new pools within existing fields. The volume of potential gas-bearing reservoir rock is calculated for known and untested traps (as in the case of suspected multizone development of an anticlinal trap) and potential but unknown traps (pools separated from current production by faults or facies changes, such as overlapping barrier bars). This calculated volume is adjusted for possible changes in lithology and reservoir characteristics as well as variations in thickness and lateral extent

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*Yield factors represent the amount of gas expected to be produced from a given unit of rock. They are calculated using data from known gas accumulations considered to be most similar to the one being evaluated. The yield is the volume of discovered gas (i.e., cumulative production plus proved reserves) divided by the volume of productive rock.

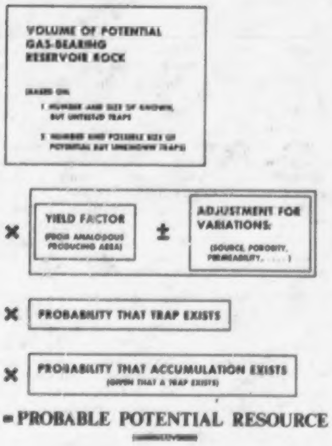
VOLUME OF POTENTIAL GAS-BEARING RESERVOIR ROCK
(BASED ON:
1. NUMBER AND SIZE OF KNOWN, BUT UNTESTED TRAPS
2. NUMBER AND POSSIBLE SIZE OF POTENTIAL BUT UNKNOWN TRAPS)
×
YIELD FACTOR
(FROM ANALOGOUS PRODUCING AREA)
±
ADJUSTMENT FOR VARIATIONS:
(SOURCE, POROSITY, PERMEABILITY, ...)
×
PROBABILITY THAT TRAP EXISTS
×
PROBABILITY THAT ACCUMULATION EXISTS
(GIVEN THAT A TRAP EXISTS)
= PROBABLE POTENTIAL RESOURCE
(UNDISCOVERED)

Figure 6 — Schematic diagram of procedure for estimation of undiscovered Probable potential supply

of the reservoir. Variations of this type might include lateral changes in the bedding such as sand pinchouts or facies changes. Proper evaluation requires a familiarity with both the nature of the formation within the province and also the local facies and structural setting. The estimated volume is multiplied by an adjusted yield factor which is obtained by analogy with a producing area similar to the potential new pool under consideration. The yield factor is adjusted to account for any differences thought to exist between the analog and the potential reservoir. These differences may include factors such as different porosities and permeabilities due to deposition within different energy regimes or to diagenetic changes resulting from different depths of burial. Presence and quality of source rocks and their maturation levels must also be considered. The amount of potential supply thus calculated must then be discounted by two factors. The first discount factor is a measure of how certain the estimator is of the existence of the traps. In the case of potential multizone anticlines, the traps are known to exist and there is no discount. It is more difficult to assess the probability of occurrence of unknown traps and a thorough understanding of the geology is important in order to make a competent evaluation. The second discount factor considers the possibility that even though all conditions are favorable for an accumulation, including the existence of a trap, gas may not actually have accumulated. For instance, the trap may not have existed at the time of migration of the gas. With inclusion of these two discount factors, an estimate of the *undiscovered Probable* potential resource can be made.

The technique for estimating *Possible* potential supply (fig. 7) is essentially the same as for the undiscovered Probable category. Both situations involve untested traps within formations productive within the province but differ in their association with proved production. Possible supplies are located within a productive province, but away from presently productive fields. For this reason it is necessary to consider the possible existence of producing trends or plays. By extending a trend or a play from a productive area into a relatively unexplored area, a reasonable geologic interpretation can be made about the number and types of traps to be found in that region. Available geophysical or geological data may also indicate the location and possible size of potential traps. Careful evaluation of the trend or play is

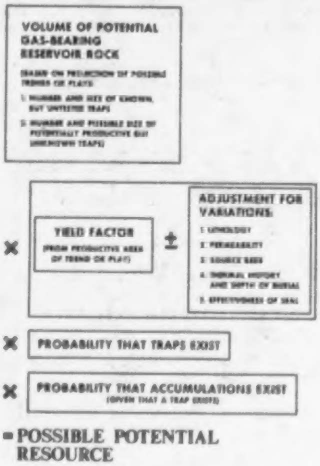
VOLUME OF POTENTIAL GAS-BEARING RESERVOIR ROCK
(BASED ON PROJECTION OF POSSIBLE TRENDS OR PLAYS:
1. NUMBER AND SIZE OF KNOWN, BUT UNTESTED TRAPS
2. NUMBER AND POSSIBLE SIZE OF POTENTIALLY PRODUCTIVE BUT UNKNOWN TRAPS)
×
YIELD FACTOR
(FROM PRODUCTIVE AREA OF TREND OR PLAY)
±
ADJUSTMENT FOR VARIATIONS:
1. LITHOLOGY
2. PERMEABILITY
3. SOURCE BEDS
4. THERMAL HISTORY AND DEPTH OF BURIAL
5. EFFECTIVENESS OF SEAL
×
PROBABILITY THAT TRAPS EXIST
×
PROBABILITY THAT ACCUMULATIONS EXIST
(GIVEN THAT A TRAP EXISTS)
= POSSIBLE POTENTIAL RESOURCE

Figure 7 — Schematic diagram of procedure for estimation of Possible potential supply

necessary to ensure proper reservoir volume and yield adjustments and reasonable estimates for trap and accumulation discounts. The probabilities for the existence of traps and accumulations are dependent on how strongly the trend or play is established and the quality and quantity of available exploration data.

The estimation of *Speculative* potential supply (fig. 8) involves estimating accumulations which may be found in untested sediments located in either producing or nonproducing provinces. Estimates are based on whether or not conditions are considered favorable for gas accumulations. The factors considered include the type of sediments to be found, structural and stratigraphic relationships, tectonic history, and thermal maturation. Yield factors are estimated using known production statistics from other provinces. In these other provinces gas is produced from formations which are different from those in the speculative province, but characteristics of the formations in both provinces are believed to be similar. Adjustments are made to allow for dissimilarities between the two provinces being compared. The probabilities that the accumulations and traps exist are generally grouped together as one discount factor in order to derive the estimate of Speculative potential resources. The experience and judgment of the estimators are critical in making estimates of Speculative potential as they are in all resource estimation.

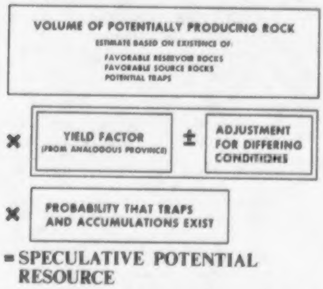
VOLUME OF POTENTIALLY PRODUCING ROCK
ESTIMATE BASED ON EXISTENCE OF:
FAVORABLE RESERVOIR ROCKS
FAVORABLE SOURCE ROCKS
POTENTIAL TRAPS
×
YIELD FACTOR
(FROM ANALOGOUS PROVINCE)
±
ADJUSTMENT FOR DIFFERING CONDITIONS
×
PROBABILITY THAT TRAPS AND ACCUMULATIONS EXIST
= SPECULATIVE POTENTIAL RESOURCE

Figure 8 — Schematic diagram of procedure for estimation of Speculative potential supply

Procedures in Estimation of Potential Gas Supply

Members of the Potential Gas Committee apply the preceding techniques for estimation of potential gas supply to each geologic province, sub-province or other geologic subdivision for which they are responsible. Natural gas accumulations generally are considered to occur in geologic basins, which are areas of thick sedimentary rocks which have accumulated in a topographic depression, resulting from tectonic processes during the geologic history of the region. However, there are some areas in the United States where natural gas has accumulated outside geologic basins (Plates I and II). Therefore, in resource estimation, inter-basinal areas must also be considered. Geologic provinces are large areas or regions which are unified in some way and which can be considered as a whole. In order to define provinces, similarity in geologic structure or stratigraphy exists throughout the province and is the defining characteristic. A geologic sub-province is a smaller area within the larger province, usually defined by close similarities in both geologic structure and stratigraphy, and in which either the same or closely similar formations exist throughout the province.

Resource estimates are made for each geologic region by members of the Committee. In many cases, especially where the potential resources are apparently quite large, two or more independent evaluations are made by individual members of the Area Work Committees. Differences between independent estimates are reconciled by discussion and re-evaluation. Each Area Work Committee, as a whole, reviews estimates of individual estimators and, based on the experience and knowledge of all members, accepts estimates presented or requests additional study and re-evaluation.

Each estimator considers three separate situations in preparing estimates:

1) The quantity of gas which might exist and be recoverable under the most favorable of geologic conditions. This assumes the maximum number of potential traps with favorable source bed and reservoir conditions, and each trap filled with recoverable accumulation. Such conditions would lead to the maximum possible resource estimate.
2) The existence of the minimum number of traps, the most marginal of source bed and reservoir conditions, and the possibility that many of the traps which might exist would not contain recoverable accumulations of natural gas. Such conditions would lead to a minimum estimate of the resource.
3) The most reasonable estimate both of the existence of traps and accumulations and the most reasonable assessment of the source bed and reservoir conditions. Such conditions would lead to the most likely estimate of the resource.

By considering all three of these situations, the estimator is best able to express both the limiting conditions within the geologic region and, also, conclude the most likely conditions to exist. Only those estimates considered to be most likely are reported by the Potential

Gas Committee. Neither the most optimistic outlook, resulting in a maximum estimate, nor the most pessimistic outlook, resulting in a minimum estimate, is believed to be a sound basis for future planning. The estimates which are reported are the best considered judgment of the members of the Committee based on their evaluation of all information available to them. However, it should be noted that there is a degree of uncertainty associated with each estimate which cannot be resolved until exploration, drilling, and production have been completed. The degree of uncertainty differs for each of the resource categories of the Committee. This uncertainty is discussed in more detail below. In order to present estimates for the reporting areas and depths of the Potential Gas Committee and for the United States as a whole, the most likely estimates for each of the geologic regions (provinces, sub-provinces, basins, etc.) are accumulated to form the totals.

Role of Judgment

The judgment of the estimator is the most significant factor in making estimates of potential supply, particularly in the resource categories of *Possible* and *Speculative*. Members of the Potential Gas Committee, having the detailed knowledge and the experience necessary to select the appropriate adjustments for an assigned geological province, use all available pertinent geological and engineering data to reflect an objective, scientific approach to the problem.

INTERPRETATION OF POTENTIAL GAS COMMITTEE ESTIMATES

The estimates presented by the Potential Gas Committee for each of the reporting areas and for each of the resource categories are statistically the *most likely* or *modal* estimates and represent the quantity of natural gas which has the highest probability of occurrence. The actual volume of ultimately recoverable natural gas within the crust of the earth is a fixed, but unknown, quantity. Consequently, the estimates made by the Potential Gas Committee necessarily involve uncertainty as to whether the best estimate of the Committee corresponds to the actual quantity of recoverable natural gas. The degree of uncertainty increases with decreasing availability of geological, geophysical and engineering information—hence, the Committee's use of the categories Probable, Possible and Speculative. *The categories Probable, Possible and Speculative relate only to the degree of certainty of the accuracy of the estimates because of the differing availability of data upon which the categories of estimates are based; the estimates presented for each category represent the Committee's objective judgment of the estimate with the highest probability of occurrence.*

It is believed that the Committee's estimates represent a distribution such that the most likely or modal estimates correspond closely to the statistical mean. Since estimates for an area are derived by combining estimates from sub-areas, it is reasonable to assume that the area estimates will follow a normal probability distribution. On this assumption, the Committee's estimates of minimum, most likely and maximum could be represented as lower, modal and upper points on a normal probability curve, and such a curve is symmetrical about the mode. The lower value corresponds to an approximately 90 percent probability that there will be at least this lower amount of recoverable gas, and the upper value corresponds to an approximately 10 percent probability that there will be this upper amount of recoverable gas.

The relationship of the most likely estimates to the probability of occurrence of natural gas resources may perhaps be best explained by reference to a hypothetical plot of the actual probability of occurrence of the given quantity of natural gas in an area (fig.9).

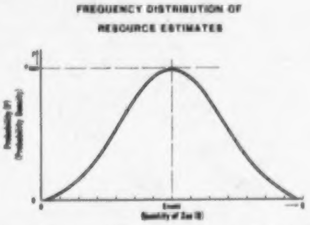

Figure 9 — Hypothetical plot of the actual probability of occurrence of the given quantity of natural gas in an area

Figure 9 demonstrates that there is the highest probability (P max) of the occurrence of a given quantity (Q mode) of natural gas at the highest, or modal, point of the curve. This Q mode is the quantity estimated by the Potential Gas Committee based on the best judgment of the members. There is a correspondingly lower probability that the actual quantity of natural gas will be something other than Q mode. Lower or higher estimates extending toward the minimum and maximum quantities which might be present can be derived by varying either the evaluation of the geologic factors which control occurrence or the discount factors applied to both the possibility of the occurrence of the trap and the accumulation of trapped gas. For example, if the reservoir conditions are not as favorable as judged by the Committee, then the quantity of gas which can be recovered would be less than that estimated by the Committee. On the other hand, if the reservoir conditions are more favorable, the quantity would be higher. Also, if the probability of both the existence of the trap and the accumulation of gas within the trap are either higher or lower, the quantity would also vary. While recognizing the possibility of this variation, members of the Potential Gas Committee feel that the most likely estimate which they present represents the best considered judgment of the Committee members as to the characteristics which exist within the area under consideration.

The "tightness" of the actual probability curve for an individual area, or the measure of uncertainty corresponding to the estimate of Q mode, will vary according to the quantity of data upon which the estimates are based and will, therefore, vary between the Probable, Possible and Speculative categories.

It can be seen from the shapes of the curves in figures 10, 11 and 12 that there is greater uncertainty about the estimate of natural gas which is to be reported as the most likely quantity for the Speculative category than for the Probable or Possible categories. That is, there is a greater range of estimates of natural gas with a relatively high probability of occurrence and, therefore, selection of the most likely estimate for the Speculative category is more difficult than for the other categories. The uncertainty diminishes in the Possible and Probable categories with the estimate of the Probable quantity being the most certain because the greatest amount of information is available.

For Probable estimates:

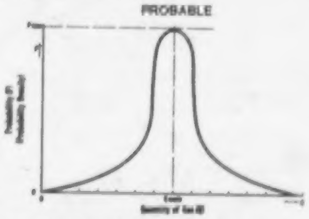

Figure 10 — Hypothetical plot of the probability of occurrence of estimates for the Probable category

A significant point to be observed in the hypothetical probability plot for the Speculative category (fig. 12) is that there is a reasonably high probability that no recoverable natural gas resource at all exists in the area under consideration. Based on the uncertainty of knowledge concerning Speculative resources, it is not surprising that there is a good chance of finding no viable gas resources at all as the result of future exploration efforts. Such a possibility of no recoverable resources also exists for the Possible resources and, to a much lesser extent, for the Probable resources. However, the probability of no recoverable gas resources is much lower for Possible resources than for Speculative resources because the existence of gas resources has already been demonstrated in the geologic province and potential reservoir formations under consideration. In the case of Probable resources, the probability of no recoverable gas resources is virtually nil.

For Possible estimates:

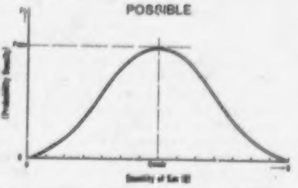

Figure 11 — Hypothetical plot of the probability of occurrence of estimates for the Possible category

For Speculative estimates:

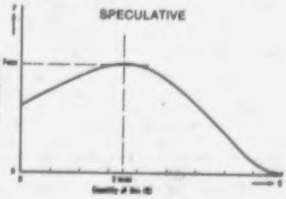

Figure 12 — Hypothetical plot of the probability of occurrence of estimates for the Speculative category

Under the conditions related to the estimates of the Potential Gas Committee, within each category the most likely estimates for each individual basin, province or trend are additive and can be combined to give the estimate for the area. The individual components of the area totals are not normally divulged by the Potential Gas Committee for two reasons, the first being that the Committee's work is often based on confidential information shared with Committee members by employers and associates. It is this shared confidential information which gives a broader base of data and greater detail and credibility to the estimates of the Committee. However, the sharing of confidential information carries with it the requirement that the confidentiality is not compromised by releasing estimates for areas which are so small that the basic data would be indirectly revealed. The reporting areas chosen by the Potential Gas Committee are large enough that the confidentiality of information is protected and yet small enough to be geologically coherent. The second reason is that, particularly when dealing with estimates of resources in the Speculative category, there may be a considerable range of uncertainty in the resource estimates for any individual basin, province or trend. By combining individual estimates for an entire area, it is hoped that overly optimistic individual estimates may be counterbalanced by other, more conservative, individual estimates and, thus, a realistic most likely estimate for the area can be achieved.

Limiting Considerations

The estimate presented here is limited to the contiguous United States, Alaska, and adjacent offshore areas. Hawaii, the island territories and their adjacent offshore areas are not included.

No potential supply of natural gas is included which exists at subsurface depths greater than 30,000 feet or, in offshore areas, where water depths are in excess of 1,000 meters (3,281 feet). Separate evaluations are made for the potential supply existing at onshore drilling depths from 0 to 15,000 feet and from 15,000 to 30,000 feet. These subdivisions recognize the greater technological and economic difficulty of recovering resources that exist below drilling depths of 15,000 feet. In offshore areas, estimates are made for the potential existing beneath water depths of 0 to 200 meters (656 feet) and 200 to 1,000 meters (3,281 feet). Estimates for water depths less than 200 meters essentially represent the potential supply that may be recovered from beneath the Continental Shelf whereas the estimates for water depths of 200 to 1,000 meters essentially represent resources that may be recovered from beneath portions of the Continental Slope.

The extension of Potential Gas Committee estimates in 1978 to include offshore areas beneath water depths up to 1,000 meters (3,281 feet) was a significant increase from the previous depth limit of the 1968 through 1976 reports which included resource estimates out to a water depth of 1,500 feet. In the opinion of Committee members, there has been sufficient improvement in drilling, production and offshore pipeline technology to warrant this extension of limits in keeping with the Committee's concept of including all natural gas resources which could be produced in the future with normal advances in technology. There still remain questions as to the capability of completing pipeline connections in offshore water depths as great as 1,000 meters. The Committee has chosen, however, to be optimistic in its outlook and to present these estimates, recognizing that the above technical questions remain unanswered.

Estimates made by the Area Work Committees include resources which exist beneath areas presently withdrawn or proposed for withdrawal from exploration and development because of governmental action. Where there exists considerable potential beneath areas so withdrawn, it is appropriate for an estimate to be made of this potential and that estimate to be presented in the narrative portion of the report submitted by each Work Area.

Economic, technological and governmental policy considerations that are taken into account in the Potential Gas Committee's estimate of potential gas supply are related to (1) past production and proved reserves of natural gas, and (2) all wells which would be drilled in the future under the assumed conditions of adequate economic incentives in terms of price/cost relationships and current or foreseeable technology. Fundamental economic considerations - which include but are not limited to prices, costs, rates of take, recovery factors, abandonment pressures, etc. - are inherent in the definition of proved reserves: " . . . recoverable in the future from known oil and gas reservoirs under existing economic and operating conditions." Some gas that is actually present in known reservoirs is not producible because of the relationship between costs and prices, and therefore is not included in recoverable reserves.

Furthermore, there are other known gas accumulations of such small size that none of the gas can be produced in commercial quantities under ". . . existing economic and operating conditions." Such considerations result in proved reserves being something less than the total volumes of gas existing in known reservoirs. These same limitations are applicable to the estimates of potential supply. If a fundamental change in economics or technology occurs, estimates of potential supply will be changed accordingly.

The attribution technique presented in the Estimation of Potential Gas Supply section describes relationships between ultimately recoverable volumes of gas from known occurrences and prospective gas accumulations, after appropriate adjustment for variations in geological and reservoir conditions are made. The explicit assumption of adequate but reasonable prices and normal improvements in technology in the definition of potential supply relates to improvements in exploration and production techniques. Adequate prices, normal techno-

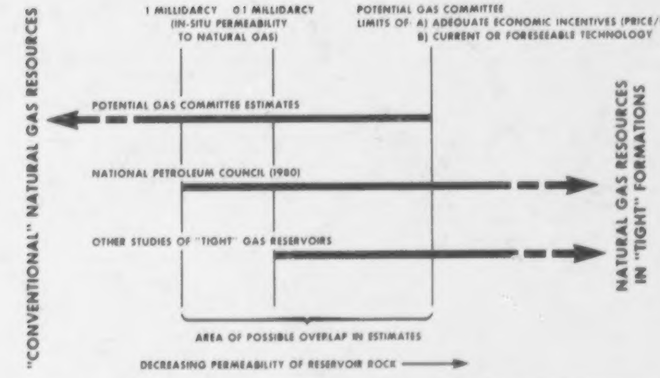
1 MILLIDARCY
0.1 MILLIDARCY
(IN-SITU PERMEABILITY TO NATURAL GAS)
POTENTIAL GAS COMMITTEE LIMITS OF: A) ADEQUATE ECONOMIC INCENTIVES (PRICE/COST) B) CURRENT OR FORESEEABLE TECHNOLOGY
"CONVENTIONAL" NATURAL GAS RESOURCES
POTENTIAL GAS COMMITTEE ESTIMATES
NATIONAL PETROLEUM COUNCIL (1980)
OTHER STUDIES OF "TIGHT" GAS RESERVOIRS
NATURAL GAS RESOURCES IN "TIGHT" FORMATIONS
AREA OF POSSIBLE OVEPLAP IN ESTIMATES
DECREASING PERMEABILITY OF RESERVOIR ROCK

Figure 13 — Schematic representation of the relationship between Potential Gas Committee resource estimates and estimates of natural gas resources in low permeability formations

logical improvements and reasonable governmental policies are required to bring about the drilling necessary to prove the potential supply. These assumed conditions permit estimates of potential supply to be made by the Potential Gas Committee on the basis of relevant past history and experience concerning recovery factors, as well as the size and type of reservoirs which have been found, developed, and produced, without speculating as to future levels of prices and costs.

In this report no potential supply of natural gas is included which might be recovered from geopressured-geothermal brines of the U.S. Gulf Coast regions, directly from gaseous coal seams, or from gas hydrates. Where coals may have served as source beds for gas accumulations in conventional sandstone or limestone reservoirs, the potential resource contained in the conventional reservoir and recoverable by conventional drilling and production is included in the Committee's estimates. The potential resource from certain black (Devonian) shales is largely excluded except that potential which the Committee believes to be recoverable by normal drilling and well stimulation and completion techniques and which is analogous in geologic setting to previous production. The natural gas potential from tight (low permeability) formations (including sandstone, shale and carbonate reservoirs) is included in the Committee's estimates to the extent that these resources fall within the limiting considerations for resource estimation.

The inclusion of resources from tight formations raises questions concerning the relationship of the estimates of the Committee to the estimates prepared by others for the resources in tight formations. No clear definition of the upper limits of what constitutes a tight gas formation has been given by most workers who have prepared estimates in the past. Some of the more recent estimates have included resources in formations with in situ effective permeabilities of up to 1 millidarcy. In the preparation of year-end 1982 estimates, the Potential Gas Committee has considered the question of the magnitude of the resources included in the Committee's estimates which might lie in formations which have in situ effective permeabilities to natural gas of less than 0.1 millidarcy. Such resources may occur in reservoir rocks of any lithology including sandstones, shales and carbonate rocks.

Figure 13 illustrates diagrammatically the overlap of resource estimates prepared by the Potential Gas Committee with the estimates prepared by others who have investigated the unconventional resource potential which may exist in formations with low permeability. Previous studies have concentrated largely on Western "tight gas sands" and Eastern Devonian shales. Estimates of the Potential Gas Committee extend from "conventional" resources to the limits of technology and economic considerations used as limiting considerations by the Committee. The Committee has determined that presently about 20 percent of its estimated resources in all categories, or about 172 trillion cubic feet, is contained in formations which have in situ permeabilities to natural gas of less than 0.1 millidarcy. These quantities have been incorporated gradually, over a number of years, into the Committee's estimates as changing technology and economic conditions have transformed a former "unconventional" resource into a "conventional" resource. Thus, currently, about 20 percent of the Potential Gas Committee estimate is probably included also in the resource estimates of those who have studied the potential from "tight gas sands" and Devonian shales. The overlap of estimates of potential with the estimates made by the National Petroleum Council study committee[1] is not known because the NPC study of tight gas formations included an undefined quantity of resources from formations with permeabilities as high as 1 millidarcy.

A review of nonconventional natural gas resources was prepared by the Potential Gas Agency and presented in Part II of the Potential Gas Committee report for 1982.[2] This review was not an independent appraisal by either the Potential Gas Committee or Potential Gas Agency of the volume of natural gas within nonconventional sources. Its purpose was knowledge and the direction of research relative to nonconventional sources of natural gas and to present published estimates of the potential from such sources. The reader is referred to this report for further information.

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[1] National Petroleum Council, 1980, Unconventional Gas Sources - Volume V - Tight Gas Reservoirs.

[2] Potential Gas Committee, 1981, Potential supply of natural gas in the United States (as of December 31, 1980): Potential Gas Agency, Colorado School of Mines, Golden, 119 p.

Estimate of Potential Supply of Natural Gas

TOTAL UNITED STATES

The potential supply of natural gas in the United States, excluding Hawaii and island territories, as of December 31, 1982, is estimated to be 192 trillion cubic feet in the Probable category, 355 trillion cubic feet in the Possible category, and 329 trillion cubic feet in the Speculative category (table 2). Figure 14 shows the geographic distribution of the potential supply as estimated by the Potential Gas Committee for each of the reporting areas for onshore and offshore resources.

Portions of this potential are less accessible than others due to technological and economic limitations. Recognizing the importance of accessibility, the potential resources have been summarized in table 3 by depth increments and by offshore water depth. The potential supply in Alaska is listed separately because of the unique conditions surrounding its accessibility to the United States' market and because Alaska is in the early stages of exploration. In all tables, dashes are used to indicate estimated potential of less than 0.5 Tcf. All estimates are based upon the volume of raw gas at 14.73 psia and 60° F.

Table 2 — Estimated potential supply of natural gas in United States by geographic areas
as of December 31, 1982
(trillions of cubic feet at 14.73 psia and 60° F.)

Area		Probable	Possible	Speculative
A	Onshore	27	8	33
	Offshore	—*	—	16
B	Onshore	6	6	7
	Offshore	1	2	28
C	Onshore	—	2	1
D	Onshore	8	20	19
E	Onshore	6	15	—
	Offshore	21	36	—
G	Onshore	12	15	4
	Offshore	11	16	—
H	Onshore	49	93	66
I	Onshore	2	3	1
J-North	Onshore	24	60	39
J-South	Onshore	15	33	1
L	Onshore	2	8	8
	Offshore	—	9	9
	48 States Subtotal	184	326	232
K	Alaska - Onshore	6	16	28
	- Offshore	2	13	69
	Total United States	192	355	329

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*In all tables, dashes are used to represent estimates of potential of less than 0.5 Tcf.

Table 3 — Total estimated potential supply of natural gas by depth increments
(trillion cubic feet)

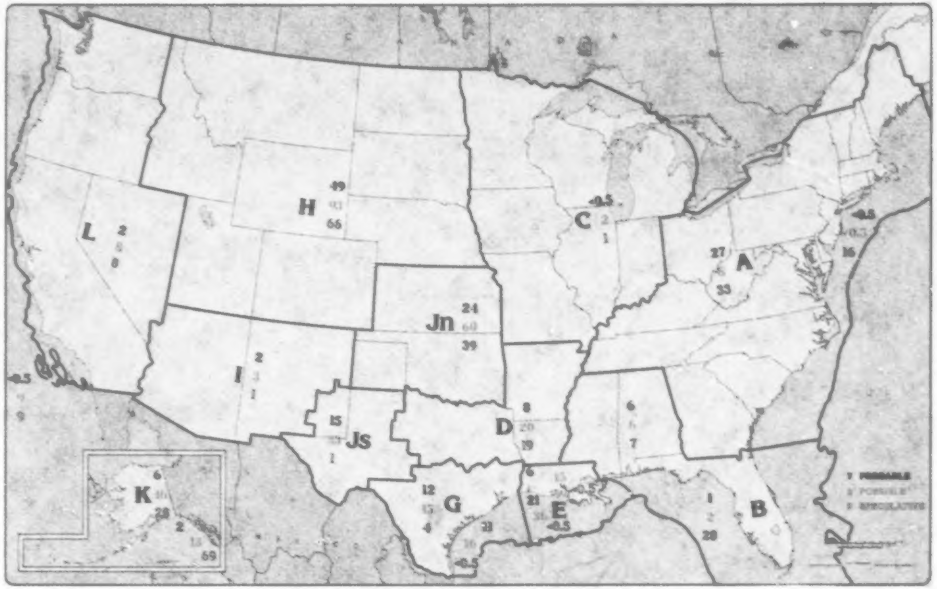
	Probable	Possible	Speculative
Onshore (Drilling Depth)			
Lower 48 States			
less than 15,000 feet	103	133	83
15,000 to 30,000 feet	48	130	96
	151	263	179
Alaska			
less than 15,000 feet	6	16	28
15,000 to 30,000 feet	—	—	—
	6	16	28
Total Onshore	157	279	207
Offshore (Water Depth)			
Lower 48 States			
less than 200 meters	30	41	30
200 to 1,000 meters	3	22	23
	33	63	53
Alaska			
less than 200 meters	2	13	59
200 to 1,000 meters	—	—	10
	2	13	69
Total Offshore	35	76	122
Total Lower 48 States	184	326	232
Total Alaska	8	29	97
Total United States	192	355	329

Probable Category

Within the onshore area of the lower 48 states, 68 percent of the Probable potential lies at drilling depths less than 15,000 feet and 32 percent lies at drilling depths between 15,000 and 30,000 feet. Eighty-two percent of the lower 48 Probable potential is in onshore areas and 18 percent in offshore areas. Within the offshore area of the lower 48 states, 91 percent of the estimated Probable potential lies beneath water depths of less than 200 meters. Ninety-six percent of the total United States Probable potential is considered to exist within the lower 48 states and 4 percent in Alaska.

Possible Category

Within the onshore area of the lower 48 states, 51 percent of the estimated Possible potential lies at drilling depths less than 15,000 feet and 49 percent lies at drilling depths between 15,000 and 30,000 feet. Eighty-one percent of the lower 48 Possible potential is in onshore areas and 19 percent in offshore areas. Within the offshore areas of the lower 48 states, 65 percent of the Possible potential lies beneath water depths of less than 200 meters and 35 percent lies beneath water depths between 200 and 1,000 meters. The Possible potential for the lower 48 states is 92 percent of the total Possible potential supply while that for Alaska is 8 percent.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B
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28
K
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1 PROBABLE
2 POSSIBLE
3 SPECULATIVE

Figure 14 — Geographic distribution of potential supply
as estimated by the Potential Gas Committee

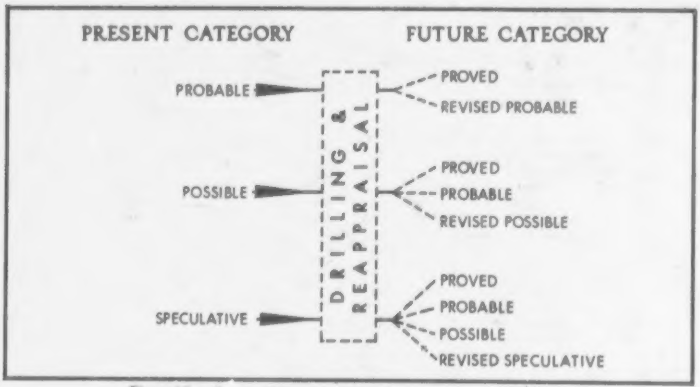

Figure 15 — Schematic representation of progression of potential gas supplies as a result of drilling and reappraisal

Speculative Category

Within the onshore areas of the lower 48 states, 46 percent of the estimated Speculative potential lies at drilling depths less than 15,000 feet and 54 percent lies at drilling depths between 15,000 and 30,000 feet. Seventy-seven percent of the lower 48 Speculative potential is in onshore areas and 23 percent in offshore areas. Within the offshore areas of the lower 48 states, 57 percent of the potential Speculative supply lies beneath water depths of less than 200 meters and 43 percent beneath water depths of 200 to 1,000 meters. The estimated Speculative supply for the lower 48 states is 71 percent of the total United States Speculative potential and the estimated Alaskan potential is 29 percent.

Comparisons with 1980 Report

Changes in estimates in each of the categories represent re-evaluation based on additional drilling. As drilling progresses, gas volumes estimated to be in a particular reservoir will move from one category to another as shown schematically in figure 15. Since any projection of potential supply lacks the accuracy of proved reserve figures, particularly in the Speculative category, it must be recognized that these estimates of potential supply will be subject to upward and downward revisions as new geological and engineering data are provided by exploratory drilling.

This report reflects continued shifts in the pattern of distribution of estimated potential supply when compared to the report prepared for year-end 1980 and to those for previous years. An increasing percentage of the potential resource is believed to lie at depths greater than 15,000 feet in onshore areas of the lower 48 states compared to shallower depths in the same areas. In 1978, 32 percent of the total onshore lower 48 resource was considered to lie below 15,000 feet. This percentage increased to 39 percent in 1980 and to 46 percent in this current report. This shift appears to result from the combination of continued development of resources from shallow, mature areas and the addition of resource potential based upon the encouraging results of increased deep exploration and drilling during the past two years. The estimate of deep resource potential has increased from 199 Tcf in 1978 to 240 Tcf in 1980 and to 274 Tcf in 1982.

The balance between onshore and offshore resources in the lower 48 states remained the same as for 1980 with 80 percent of the resource believed to exist in onshore areas and 20 percent in offshore areas. The decrease in the offshore estimates from 157 Tcf in 1980 to 149 Tcf in 1982 represents largely the maturity of the Gulf Coast region and the continued development of its resources. There has been a shift of some offshore potential in Area B from Speculative to Possible and Probable because of recent discoveries at the mouth of Mobile Bay.

Alaska is now estimated to contain 15 percent of the total resource potential compared to 16 percent in 1980 and 19 percent in 1978. The results of geophysical surveys and wildcat drilling have diminished what was previously considered to be prospective acreage in Alaska.

AREA REPORTS

Area A: Ohio, Kentucky, Tennessee, Georgia, and All States Farther East and Adjacent Offshore

Area A includes the Appalachian basin, the southern portion of the Illinois basin, the Triassic basins and the Offshore Atlantic. The Area has oil and gas production from the Appalachian foreland and Valley and Ridge regions and includes the region of oldest gas and oil production in the United States. All current production is onshore, although several attempts have been made to establish production offshore in both the Baltimore Trough and Georges Bank basin areas.

The Appalachian Mountains are the oldest major mountain group in the United States, having been deformed during both early and late Paleozoic time. Extensive "sheets" of sedimentary rocks are gently folded in the main Appalachian basin but are more complexly and tightly folded in the Valley and Ridge area to the east. Much recent attention has been focused on the "Appalachian or 'Eastern' overthrust belt", the covered portion of which includes the Blue Ridge Mountains and Piedmont of the Appalachian provinces. To date no major oil and gas discoveries have been made in the older rocks of this belt.

Paleozoic reservoirs of the Appalachian foreland supply most of the production in this area. Cambrian and younger rocks all have potential. Rocks of younger than Permian age are not present. Sandstones, limestones and fractured shales produce. The Cincinnati arch of Ohio, West Virginia and Kentucky is a major geologic structure which controls production from both structural accumulations and stratigraphic trapping.

Although most of the Area's production is from the Appalachian foreland, some production is in northwest Ohio, arcing across the southwestern margin of the Michigan basin. Scattered production in the Kentucky part of the Illinois basin is also included in this Area.

Major interest in gas potential of Devonian black shales remains; these shales have poor permeability, but, where naturally fractured, can produce gas in commercial quantities.

There have been no significant changes in the estimates of potential gas resources for Area A in 1982 compared to 1980. Discoveries have resulted in shifting of 1 Tcf from Possible to Probable resources. Continued disappointments in the exploration of offshore areas have caused Committee members to reduce further the estimate for potential gas resources in the offshore portion of Area A by 2 Tcf.

New interpretations of Appalachian geology, especially the concept of the Eastern Overthrust Belt, have spurred exploration. Wildcat drilling is taking place from the southern boundary of Area A in Tennessee to the northern portion in western Vermont. There is also renewed interest in the possibility of gas accumulation in Triassic fault-block basins along the Atlantic margin. Hopefully, the results of this exploration will lead to better evaluation of the resource potential of portions of this area where the geologic setting and structural characteristics are still only poorly known.

Table 4 — Area A. Eastern United States
Ohio, Kentucky, Tennessee, Georgia, and all states farther east
and adjacent offshore
(trillion cubic feet)

	Probable	Possible	Speculative
Onshore (Drilling Depth)			
less than 15,000 feet	27	8	22
15,000 to 30,000 feet	—	—	11
Total	27	8	33
Offshore (Water Depth)			
less than 200 meters	—	—	11
200 to 1,000 meters	—	—	5
Total	—	—	16
Area A total	27	8	49

Area B: Mississippi, Alabama, Florida and Adjacent Offshore

The principal prospective areas in Area B include the Mississippi-Alabama Interior Salt basin of south Mississippi, southeastern Alabama and the very western portion of the Florida panhandle, and the Black Warrior basin of northeastern Mississippi and northwestern Alabama. Other areas of interest include the Wiggins uplift and the Hancock Ridge of south Mississippi, the offshore extension of the Mobile graben and the Appalachian thrust belt of northern Alabama.

The Interior Salt basin and the Mobile graben area of lower Mobile Bay, has prolific production from Jurassic-age rocks which include the Cotton Valley, Smackover and Norphlet Formations. The Interior Salt basin also has production from Late and Early Cretaceous age rocks, with the Hosston Formation being the most important Lower Cretaceous gas producer. Cenozoic production is found in southwestern Mississippi from the Wilcox Group of the Eocene and from Miocene sandstones in south Alabama and just offshore. Salt uplift and the associated faulting are the principal trapping mechanisms in these areas, but stratigraphic traps also form accumulations either on regional dip or associated with nosing or salt-related features. The stratigraphy consists primarily of clastic rocks with the exception of the Selma Chalk of Late Cretaceous age, the James Limestone and Sligo Formation of Early Cretaceous age and the Smackover Formation of Jurassic-age. The Smackover produces from both dolomite and oolitic limestones.

Paleozoic production in Area B is found in the Black Warrior basin. Production is from Pennsylvanian and Mississippian sandstones with a small portion of production from the Mississipian Bangor Limestone. No significant production has been established from Cambrian or Ordovician rocks. Most of the production is structurally controlled except for an area of Fayette County, Alabama, where production is stratigraphically controlled. Exploration for Paleozoic production in the Appalachian overthrust of Alabama is just beginning and will be an area of interest for the next several years.

The 1982 estimate of potential gas resources for the southeastern states of Mississippi, Alabama, Florida and the adjacent offshore areas out to the 1,000 meter water depth is 50 Tcf. This is a reduction of 4 Tcf (7.4%) from that estimated in the 12/31/80 report. The changes in the estimate of potential gas resources onshore has resulted in a 2 Tcf downward revision from the 12/31/80 estimate. These changes are due to the disappointing results of wildcat drilling in the area. The potential gas resources estimate for the offshore portion of Area B has also been lowered by 2 Tcf. This reduction was prompted by the results of drilling in the South Florida basin area. As a result of the drilling being done in the lower Mobile Bay area of Alabama, 3 Tcf has been moved from the offshore Speculative category into the Probable category (1 Tcf) and Possible category (2 Tcf).

The primary exploration effort onshore has been to extend the Hosston production into other areas and to develop reserves in the deep Cotton Valley trend of south Mississippi. The results of both of these efforts have been disappointing. In west-central Mississippi, where the Cotton Valley is shallower, several discoveries have been made. This is an area in which exploration activity will expand. In the Black Warrior basin of northwestern Alabama and northeastern Mississippi, there continues to be strong interest in exploration and development of shallow Palezoic fields. The thrust and fold belt of Alabama is beginning to experience an exploration thrust for Paleozoic production.

Table 5 — Area B. Southeastern United States
Mississippi, Alabama, Florida and adjacent offshore
(trillion cubic feet)

	Probable	Possible	Speculative
Onshore (Drilling Depth)			
less than 15,000 feet	4	3	3
15,000 to 30,000 feet	2	3	4
Total	6	6	7
Offshore (Water Depth)			
less than 200 meters	1	2	15
200 to 1,000 meters	—	—	13
Total	1	2	28
Area B total	7	8	35

Development drilling in the lower Mobile Bay field continues with 4 wells completed. Three wells were completed in the Jurassic and the fourth was completed in the Miocene. One well is presently drilling and three others are permitted.

There have been no tight gas sands so designated in Area B to date. Several formations meet the requirements to be classified as tight gas sands in some portions of Area B. Estimates indicate that 2 Bcf (4%) of the potential gas resources in this area may be found in tight gas sands.

Area C: Minnesota, Wisconsin, Michigan, Iowa, Illinois, Indiana, and Missouri

Area C comprises the Michigan basin, the Illinois basin and Forest City basin. Oil and gas development in Area C is largely restricted to the Michigan basin, Kankakee arch, and Illinois basin, although a much broader geographic area is included. A minor amount of hydrocarbon production occurs in the Missouri portion of the Forest City basin.

Production is from Ordovician through Pennsylvanian-age rocks, both sandstones and carbonates. The major exploration targets in the Michigan basin are Middle Silurian Niagaran pinnacle reefs. In addition, there is increased interst in exploring the central basin area of the Michigan basin where deeper drilling on known Mississippian and Devonian structures has been rewarded mainly with oil pays in the Devonian Richfield interval. The first production of gas from the Ordovician Prairie du Chien Group in north-central Michigan has generated great interest in finding more production from depths greater than 10,000 feet. The giant Trenton Field of Indiana produces from shallow Ordovician dolomites (and has since 1886); Devonian and Mississippian reservoirs are more common in the Illinois basin.

Area C has not been severely deformed during Phanerozoic time, although severe earthquakes from motion along ancient fracture systems have shaken southeastern Missouri as well as parts of Illinois. Large arch and basin systems with low relief are characteristic of the region. Lack of source rocks coupled with thin sedimentary cover and lack of thermal maturity have apparently precluded formation of hydrocarbon pools in Minnesota, Wisconsin and Iowa.

The December 31, 1982, total potential gas supply estimate has been revised downward from the 1980 estimate by approximately 60 Bcf because of exploration results related to new Devonian gas resources and because of the transfer of 400 Bcf of potential Silurian resources to proved reserves and production. These decreases were offset partially by an increase of 265 Bcf in the estimate of potential supply that is attributed to other Prairie du Chien gas resources believed to be in the Michigan basin. Although the net result of these changes is a decrease of 195 Bcf in the overall estimate for Area C, this has not resulted in a change in the reported estimates of Possible and Speculative potential because of Committee policy to round estimates to the nearest trillion cubic feet.

The major current exploratory activity continues to be Niagaran pinnacle reefs in the Michigan basin.

Currently, the potential gas resource assigned to offshore areas of the Great Lakes is not available for development because of Michigan legislation and State Natural Resource Commission policy.

Table 6 — Area C. North Central United States
Minnesota, Wisconsin, Michigan, Iowa, Illinois, Indiana, and Missouri
(trillion cubic feet)

	Probable	Possible	Speculative
Onshore (Drilling Depth)			
less than 15,000 feet	—	2	1
15,000 to 30,000 feet	—	—	—
Area C total	—	2	1

Area D: Arkansas, North Louisiana, and Central Texas (RR Comm. Dists. 5, 6, 7B and 9)

From the standpoint of prospective areas, Area D includes the North Louisiana, East Texas, Forth Worth and Hardeman geologic basins as well as the southern part of Arkansas south of the Ouachita System forelands. Three major producing regions occur in Area D: Eastern Arkoma basin production in northwestern Arkansas, the East Texas and Northern Louisiana basins in the central part of Area D, and the Fort Worth basin and North-Central Texas shelf in the west. These are structurally and stratigraphically diverse areas representing three geologic provinces.

Paleozoic rocks are major producers in the Arkoma basin to the north of the Ouachita fold belt and south of the Ozark dome. This area was deformed during Mississippian and Pennsylvanian time. The lower Paleozoic rocks are shelf limestones and clastics; upper Paleozoic rocks tend to be more dominantly clastic. North-Central Texas production is largely from Pennsylvanian clastic rocks.

The eastern Texas, southern Arkansas and northern Louisiana production is from the East Texas basin, the Sabine uplift, and the Northern Louisiana basin. This famous area produces from sandstones and some limestones of Jurassic, Cretaceous and Eocene age. Jurassic Smackover, Eocene Wilcox and, more recently, Jurassic Cotton Valley reservoirs produce large quantities of gas, with the deep Cotton Valley in the East Texas basin being a major target in recent times.

The estimates for all categories of potential supply in Area D were reduced from the last report, with Probable reduced 1 Tcf, Possible reduced 2 Tcf and Speculative reduced 1 Tcf, for a total reduction of 4 Tcf covering the three categories. These reductions were due mainly to the shifting of potential supply to proved reserves and production as a result of the high level of exploration across almost all portions of Area D since the last report. Drilling activity has decreased somewhat from the record pace seen in 1981; however, considerable exploration activity continues in most basins of Area D.

Table 7 — Area D. Arkla-Tex
Arkansas, North Louisiana, and Central Texas
(RR Comm. Dists. 5, 6, 7B & 9)
(trillion cubic feet)

	Probable	Possible	Speculative
Onshore (Drilling Depth)			
less than 15,000 feet	8	20	15
15,000 to 30,000 feet	—	—	4
Area D Total	8	20	19

Area E: South Louisiana and Offshore Louisiana

Area E comprises the Louisiana Gulf Coast onshore and offshore. Sedimentary rocks of Cretaceous (Tuscaloosa), Eocene (Wilcox), Oligocene (Frio-Hackberry) and Miocene age were deposited by overlapping and coalescing Mississippi River drainage flood plains and delta complexes in the onshore part of Area E. Structures, especially salt domes and faulting, which were actively moving during deposition of these sandstones and shales formed composite stratigraphic-structural traps as well as less-complex structural traps. In the offshore Louisiana province, rapid sedimentation of clastic sediments continued into more recent geologic times and has provided reservoir rocks of younger age. Production offshore is largely from Miocene, Pliocene and Pleistocene rocks.

The onshore and offshore areas are both well known for the production associated with salt domes. These large structures are piercements formed by the upward movement of the Louann Salt (Jurassic). This upward movement disrupted normal sedimentary layers and created oil and gas traps at the contacts between upturned edges of sandstones and impervious salt. These salt diapirs are probably caused by unequal loading of heavy sediments on the relatively low density salt beds or by movement along growth faults. The caps of the salt diapirs commonly contain large amounts of native sulfur.

The estimated potential supply of natural gas from Area E has been decreased by 3 Tcf from the estimates of 12/31/80. The new estimate of the total potential supply is 78 Tcf. Virtually all of the decrease in estimates is related to transfers from potential supply to proved reserves in this actively developing area. The net result of evaluation of new data and reappraisal of earlier estimates accounts for the remainder of the decrease.

The major exploratory activity in Area E continues to be the deep Tuscaloosa Trend, which extends in a belt approximately 20 miles wide and 300 miles long from Texas to Mississippi across the northern portion of south Louisiana. Over 30 discoveries have been made in the trend since the play began in 1975, and both exploratory and development drilling is still active, although at about half the level of two years ago. Other significant exploratory developments include two recent Cretaceous (Tuscaloosa) discoveries in lightly drilled St. Helena Parish, which had been the only parish in the State of Louisiana that did not have commercial production.

Potential gas resources of approximately 1-1/2 Tcf are estimated to be contained within the 300,000 plus acres of federal lands designated as National Wildlife Reserves where all mineral exploration and development have been formally prohibited.

Table 8 — Area E. South Louisiana and adjacent offshore
(trillion cubic feet)

	Probable	Possible	Speculative
Onshore (Drilling Depth)			
less than 15,000 feet	3	4	—
15,000 to 30,000 feet	3	11	—
Total	6	15	—
Offshore (Water Depth)			
less than 200 meters	20	23	—
200 to 1,000 meters	1	13	—
Total	21	36	—
Area E total	27	51	—

Area G: Texas Gulf Coast and South Texas (RR Comm. Dists. 1, 2, 3 and 4) and Adjacent Offshore

Area G includes south Texas and the Texas Gulf Coast, both onshore and offshore. During the opening of the Gulf of Mexico, tension and stress created a system of faults parallel to the present coast which are downthrown to the Gulf. These faults have continued to move at the same time sedimentation has taken place from the Jurassic Period through modern times and control much of the onshore and some offshore production. Additionally, the northeastern part of the Area falls within the Gulf Coast salt dome basin. Both structural traps and structurally assisted stratigraphic traps are found. Production is largely from upper Mesozoic and Cenozoic rocks, but occurs in rocks as old as Ordovician and as young as Pleistocene.

One of the most important exploration plays at the present time is the Austin Chalk, a Cretaceous limestone. Other major targets are Wilcox sandstones (Eocene) and Frio sandstones (Oligocene). In general, oldest rocks are penetrated and produce most frequently in the northern part of Area G on the flank of the Llano uplift. Southward, toward the Gulf of Mexico, successively younger rocks produce; the exposed sedimentary rocks also are younger in the same direction. None of the area has been severely deformed since formation of the major producing reservoirs.

The estimate of total potential supply for Area G has been reduced by 11 Tcf from the estimate of 12/31/80. This reduction in the estimates consists of 3 Tcf each in the onshore Probable and Possible categories, 4 Tcf in the offshore Probable category and 1 Tcf in the offshore Possible category. There is no change in the estimate of Speculative potential. The changes are a net result of reevaluation of the area where considerable information is now available and transfers of discoveries from potential resources to proved reserves. About two-fifths of the decrease is related to transfers to proved reserves.

The main areas of exploratory and major drilling activity onshore in Area G are the Austin Chalk (Upper Cretaceous) in RR Districts 1 and 3, the Wilcox in Zapata and Duval Counties of RR District 4, the Frio Trend of Districts 2, 3 and 4, the Woodbine-Tuscaloosa activity of District 3 and the promising deep Sligo activity in Districts 1 and 2. Offshore, the Brazos, High Island, Matagorda, and Mustang Island areas continue to lead in significant drilling for Miocene objectives.

Table 9 — Area G. Texas Gulf Coast and South Texas
(RR Comm. Dists. 1, 2, 3 & 4) and adjacent offshore
(trillion cubic feet)

	Probable	Possible	Speculative
Onshore (Drilling Depth)			
less than 15,000 feet	7	9	2
15,000 to 30,000 feet	5	6	2
Total	12	15	4
Offshore (Water Depth)			
less than 200 meters	9	11	—
200 to 1,000 meters	2	5	—
Total	11	16	—
Area G total	23	31	4

Area H: North and South Dakota, Nebraska, Montana, Wyoming, Idaho, Colorado, and Utah

Gas and oil production in Area H is obtained from a diverse group of geologic settings, reservoir ages and environmentally restricted areas. Comprising the states of North and South Dakota, Nebraska, Montana, Idaho, Wyoming, Utah and Colorado, Area H includes sedimentary basins and producing areas of shallow, cratonic rocks as well as deep, geosynclinal provinces. Although many different ages of rocks produce hydrocarbons, Ordovician and Mississippian rocks are the major producers in the Williston basin of North Dakota, eastern Montana and South Dakota, whereas Cretaceous rocks are the most significant gas producers in the Wyoming intermontane basins, the Uinta-Piceance basins of Utah and Colorado, the Denver-Julesburg basin of Colorado, and the San Juan basin of northwestern New Mexico and southwestern Colorado. Most production in the Paradox basin of southeastern Utah is from rocks of Pennsylvanian age. Production from the Western Thrust Belt in Wyoming and Utah ranges from Cretaceous oil production to Mississippian and Devonian gas-condensate production.

The Williston basin is known more for its oil production than gas; however, in the past four years, significant new gas discoveries in the Ordovician Red River and the Winnipeg Formations in the deeper parts of the basin have demonstrated that there are significant resources of gas yet to be discovered there. This basin is particularly significant for the Rocky Mountain province because its producing rocks are mostly limestones and dolomites, rather than sandstones. A few reefs are known in the basin, but these do not contribute significant gas production.

The southern part of the Alberta basin extends into Montana. It has gas production from Cretaceous and Jurassic rocks, particularly in the Bowdoin dome area, but also around the Bearpaw uplift and the Sweetgrass arch to the west.

Production from the Denver-Julesburg basin is largely from Cretaceous rocks in the western part of this asymmetric, yoked basin. The basin is faulted down against the Front Range of the southern Rocky Mountains and gently rises to the east (Nebraska and Kansas). Extensive drilling has proven that the tight limestones (chalks) of the Niobrara Formation (Cretaceous) in the eastern part of the basin will add significant reserves to the natural gas supply. Drilling in the Denver basin for Paleozoic sandstones and carbonates is sparse. Further exploration of Paleozoic-age reservoirs may result in the discovery of additional fields similar to Amazon field in southwestern Nebraska, which produces oil from a Pennsylvanian-age carbonate section.

Powder River basin exploratory activity has continued at high levels, particularly for targets of Cretaceous and Permian ages. Modern remote-sensing concepts, sophisticated stratigraphic-seismic techniques and newer structural theories, coupled with increased drilling in the northern half of the basin, should provide significant new reserves, primarily of oil.

Other intermontane basins of Wyoming, such as the Green River, Big Horn and Wind River, produce large quantities of gas from Cretaceous and early Cenozoic rocks, with deeper horizons showing much promise. However, the drilling depths of over 20,000 feet so far have precluded detailed evaluation of deep reservoirs. Along mountain fronts, steep "ramp" thrust faulting has created the potential for large accumulations of gas, but exploration is extremely expensive and risky. The

Uinta and Piceance basins are similar, in some respects, to the Wyoming basins, and extensive reserves of gas are being developed there in low-permeability ("tight") sandstones of Cretaceous age.

Perhaps the most exciting portion currently of Area H from an exploration standpoint is the Western Thrust Belt or Overthrust Belt. This really is a series of at least three separate structural provinces, each characterized by a very thick sedimentary rock section that has been broken into slabs. These slabs have been stacked and thrust so that wells may penetrate individual rock units several times during drilling. Production is generally from structures buried under one or more of these slabs or thrust sheets. Exploration in the Central, or Middle, Thrust Belt (western Wyoming and northeastern Utah) has encountered prolific gas resources. The Southern Thrust Belt (central Utah and southeastern Nevada) so far has not been found productive. In the Northern Thrust Belt, or Disturbed Belt, of northeastern Montana, potentially significant gas reserves are being developed in Mississippian-age carbonate rocks. While most geologic factors are favorable to hydrocarbon accumulations, extreme technical difficulties in mapping subsurface rocks, coupled with high temperature gradients, make this province extremely high-risk for drilling at this time.

All of Area H is subject to stringent environmental restrictions, because the area includes much of the Rocky Mountain province. In many areas, such as the Thrust Belt, exploration activity is destined to take place in the most scenic parts of the American West. If petroleum exploration is to continue, and even to expand, in these environmentally sensitive mountainous areas, more attention must be given to the mitigation of the environmental impacts of such operations.

Estimates of the natural gas potential for Area H have been increased from the 12/31/80 figures by 9 Tcf in the Probable category and 15 Tcf in the Possible category and decreased by 3 Tcf in the Speculative category. Overall, the new estimates for Area H show a net increase of 21 Tcf.

For the first time, this biennial report includes estimates of the percentages of the potential supply of natural gas in each category that are believed to lie in low-permeability, or "tight", reservoirs. More than half of the estimated potential Probable and Speculative supply of natural gas in Area H is believed to be in the "tight" category (table 16).

Changes in the Probable and Possible potential supply of natural gas throughout Area H have resulted primarily from data provided by new, generally deep (greater than 15,000 feet), discoveries in the Williston, Green River, Wind River, and Piceance Creek basins and in the Central Thrust Belt. Decreases in the Speculative category resulted from re-evaluations of certain areas in Montana and in the Powder River and Green River basins.

In Montana (exclusive of the Williston basin), the total potential resources (in all three categories) have been decreased approximately 4 Tcf due to the fact that few significant gas discoveries have been made in recent years, with the exception of the Western Montana Disturbed Belt (or Northern Thrust Belt), where gas has been discovered in feulted Mississippian carbonate rocks.

In the Williston babin, the total potential resources have been increased by approximately 1 Tcf in the Probable category as a result of the discovery of gas in the Ordovician Red River and Winnipeg Formations at depths ranging from approximately 11,500 feet to more than 14,000 feet.

Wind River basin Possible resources have been increased by approximately 4 Tcf due to a significant discovery of gas on the eastern margin of the basin in subthrust Cretaceous sediments below 18,000 feet. This well, which drilled through a wedge of Percambrian granite nearly 9,000 feet thick, marks the first commercial discovery in the region beneath a mountain-front thrust sheet.

In the Greater Green River basin, estimated total potential resources have been increased by approximately 16 Tcf in the combined Probable and Possible categories as a result of including, for the first time, the methane fraction (approximately 22%) contained in low-Btu gas that is known to occur below 15,000 feet in Paleozoic-age reservoirs in the Big Piney-La Barge area. in the western part of the basin. Potential resources in Cretaceous-age reservoirs in both major depth categories have been reduced somewhat due to poorer than expected performance of such wells, especially at depths below approximately 12,000 feet.

The methane fraction (about 22%) in the low-Btu gas estimated for the Big Piney-La Barge area (or Moxa arch), in both the western Green River basin and Central Thrust Belt blocks, ranges from a minimum of 16 Tcf to a maximum of 52 Tcf, with 31 Tcf being the most likely figure. Recent deep discoveries have found high flow rates of low-Btu gas from the Permian Phosphoria, Pennsylvanian Weber, Mississippian Madison and Ordovician Big Horn Formations.

In the Central Thrust Belt (or Wyoming-Utah-Idaho Overthrust Belt), estimated total potential resources have been increased by a net 5 Tcf in the Probable category as a result of counting the methane content of low-Btu gas for the first time. In the Speculative category, at least 50 percent of the natural gas resources (43 Tcf) expected to be found in Cretaceous-age clastic reservoirs probably will be classified as "tight" gas.

Deep exploration in the Big Horn, Powder River, Uinta, and Piceance Creek basins has resulted in little or no increase in potential resources estimated for any of the categories. Potential resources in the Denver basin, in western Nebraska and in southeastern Colorado, have been slightly increased in all three categories as a result of new discoveries in both Cretaceous and Permo-Pennsylvanian sequences, all at depths less than 15, 000 feet. In the Paradox basin, small decreases have been recorded for both the Possible and Speculative categories. For the first time, potential resources (Speculative) have been estimated for Idaho (exclusive of the Central Thrust Belt), in the Snake River downwarp.

Drilling to depths in excess of 15,000 feet in the deeper Rocky Mountain sedimentary basins has increased significantly in the past two years in provinces such as the Central Thrust Belt, in the Big Horn, Powder River, Wind River, Green River and Piceance Creek basins and along the Southern Thrust Belt (or "Hingeline") in west-central Utah. A drilling well in the eastern Wind River basin is projected to a total depth of 26,500 feet, which should establish a record for the Rockies. Two-thirds of the 61 "deep" wells drilled in Area H during 1981 were successful. Most of the gas produced from clastic reservoirs at these depths, no doubt, will be classed as "tight" gas following current Federal Energy Regulatory Commission definition.

Perhaps as much as 50 percent of the mountainous flanks of several of the petroliferous Rocky Mountain basins and associated uplifts either have been formally withdrawn or presently are unavailable for energy resource exploration and development as a result of environmental sensitivities or restrictions. In scenic areas such as the Southern, Central and Northern Thrust Belts, a significant percentage of the estimated potential gas supply thus may be legally unavailable.

Table 10 — Area H. Northern Rocky Mountains
North and South Dakota, Nebraska, Montana, Wyoming, Idaho, Colorado, and Utah
(trillion cubic feet)

	Probable	Possible	Speculative
Onshore (Drilling Depth)			
less than 15,000 feet	29	37	26
15,000 to 30,000 feet	20	56	40
Area H total	49	93	66

Area I: Arizona and New Mexico

Producing areas of Area I include the San Juan basin which extends from northern New Mexico into southwestern Colorado and the Defiance uplift of northeastern Arizona. The Defiance uplift has been disappointing in its success; its most important field produces from fractured igneous rock. However, the San Juan basin is a major gas-producing basin which is now receiving new emphasis for oil production as well.

Structurally allied with the Colorado Plateau province, the San Juan basin received marine and non-marine sedimentation during Cretaceous time with organic shales and some carbonates being intercalated with sandstone wedges derived from erosion of the early western Rocky Mountain uplift.

Gas is produced from Upper Cretaceous sandstones, primarily associated with the Pictured Cliffs Sandstone, the Mesaverde Group and the Dakota Group, while oil is produced more commonly from the Upper Cretaceous Gallup Sandstone. Deep drilling is sparse, but there may be resource potential in Jurassic sandstones and possibly in Pennsylvanian carbonates. High drilling density and production in the shallower Cretaceous rocks precludes effective deeper exploration until present reserves are depleted.

Two other major tectonic provinces exist in Area I that have had recent, albeit unsuccessful, attention. The Rio Grande rift system is an active tectonic zone which may have geothermal potential. Southern Arizona is part of the Basin and Range Province which has been suggested as a southern extension of the Western Thrust Belt. No successful exploration attempts have been recorded despite some very interesting attempts to validate the overthrust hypothesis by penetrations through Precambrian crystalline rocks.

There has been no significant change in the estimate of resource potential of Area I since the 1980 report. Except for some peripheral San Juan basin area drilling, the exploratory activity has been sporadic and disappointing across Area I.

Current activity, although meager, is primarily limited to a few shallow, scattered exploratory tests in Arizona. It is believed there will be continued, but limited, activity in the possible "Overthrust Belt" in southern Arizona.

Table 11 — Area I. Southern Rocky Mountains
Arizona and New Mexico
(trillion cubic feet)

Onshore (Drilling Depth)	Probable	Possible	Speculative
less than 15,000 feet	2	3	1
15,000 to 30,000 feet	—	—	—
Area I total	2	3	1

Area J-North: Mid-Continent Kansas, Oklahoma, and Texas RR Comm. Dist. 10

Production of oil and gas in Area J-North is from several geologic provinces including the western Arkoma basin, Anadarko basin, Hugoton embayment, central Oklahoma region, Central Kansas uplift, Nemaha ridge, Salina basin, and Forest City basin.

With the exception of the Anadarko basin, these geologic provinces are characterized by relatively thin sedimentary units covering large areas with many broad structures. The province is tectonically well up on the continental plate and unaffected by large orogenic movements, although vertical uplifts are common. Rocks that produce hydrocarbons range from Cambrian to Permian in age.

Stratigraphic traps in Pennsylvanian sandstones have been very important in the Anadarko basin. Much of the sandstone of Pennsylvanian age is associated with uplift of fault blocks during late Mississipian and Pennsylvanian time to form parts of the Ancestral Rocky Mountains and parts of the Ouachita fold and thrust belt. Detritus from these uplifts as well as cratonic drainage has created numerous potential hydrocarbon reservoirs and helped create the source rocks for some of them. Earlier Paleozoic reservoirs are largely cratonic sedimentary rocks, excluding both mudstones and limestones. Pennsylvanian limestones are important producing reservoirs in Kansas where these rocks are cyclic in nature.

In the deformed areas of the Anadarko basin and adjacent areas, production is also from Paleozoic rocks, but faulted structures are important to accumulations. Thermal gradients have been higher than in the shallower areas with consequently higher gas-oil ratios and greater overall hydrocarbon potential.

The estimates of potential supply above 15,000 feet in Area J-North have decreased by 3 Tcf in the Probable category and by 5 Tcf in the Possible category, while the estimate for the Speculative category remains unchanged since the estimates for 12/31/80. Approximately one-half of the decrease is due to transfers from potential supply to proved reserves.

Below 15,000 feet the estimates of potential supply have decreased by 1 Tcf in the Possible category and by 3 Tcf in the Speculative category, while the estimate for the Probable category has remained unchanged since the 12/31/80 estimates. Approximately one-third of the decrease is due to reserve additions that were removed from potential supply during the two-year period.

The record amount of drilling activity seen in Area J-North in the past two years has helped evaluate several areas and several drilling target horizons. There were major disappointments in some areas such as the deep Pennsylvanian Springer sands in the Cyril sub-basin of the southeastern Anadarko basin in Oklahoma, but significant discoveries were made in all parts of the Area to give justification to the estimates made for most other areas. By 12/31/82 there had been a marked decrease in the amount of drilling activity in Area J-North compared to what was seen a year earlier, but the activity in 1982 would still rank within the top three years for most parts of the area.

Oklahoma established a new producing depth record in a recent completion from the Hunton Formation (Siluro-Devonian) in Beckham County. The well flowed over 14 million cubic feet of gas per day from below 24,928 feet.

The portion of resource not currently available for exploration and production due to environmental restrictions or withdrawals from exploration within Area J-North is insignificant.

Table 12 — Area J-North. Mid-Continent
Kansas, Oklahoma, and Texas RR Comm. Dist. 10
(trillion cubic feet)

	Probable	Possible	Speculative
Onshore (Drilling Depth)			
less than 15,000 feet	15	22	5
15,000 to 30,000 feet	9	38	34
Area J-North total	24	60	39

Area J-South: Permian Basin S.E. New Mexico (Chaves, Eddy, Lea & Roosevelt Cos.) and Texas RR Comm. Dists. 7C, 8 & 8A

Area J-South comprises the world-famous Permian basin. Although production is from rocks as old as Ordovician, the major oil and gas production from this region is associated with Pennsylvanian and Permian carbonates that formed an extensive complex of organic reefs and reef-associated environments.

Thick sections of early Paleozoic rocks were accumulated along the Continental Shelf, including potential source rocks. During the Appalachian-Ouachita-Marathon-Ancestral Rocky Mountains orogenic episode that deformed much of the United States' cratonic margin in late Paleozoic time, structural reversal and development of basins and platforms occurred in the Permian basin region, which is mountain-bounded on the north by the Matador uplift and on the northwest and west by the Pedernal uplift. As these uplifts were eroded, their detritus was spread into the basins while carbonate deposition was occurring simultaneously on isolated platforms. Eventually much of Area J-South was covered by shallow marine carbonates or nearshore clastics.

The reefs that developed along platform edges, the detritus that spilled into the basins, older rocks with structural trapping factors, and nearshore sedimentary rocks with stratigraphic hydrocarbon accumulations have all contributed to the production of the area. Although more potential hydrocarbons exist, this area is reaching maturity as an exploration area.

The estimates of the potential gas resource for Area J-South have been reduced in the Probable and Possible categories. Estimates of Probable resources at depths less than 15,000 feet have been revised downward 1 Tcf from 8 Tcf to 7 Tcf. The estimates of Possible resources at depths from 15,000 to 30,000 feet were reduced 1 Tcf from 15 Tcf to 14 Tcf. Resource estimates for the remaining categories were unchanged. All of this decrease can be accounted for by transfers from potential resources to proved reserves.

The Delaware basin is one of the primary exploratory areas in west Texas and the center of activity has been Loving County. Operators were drilling deeper to find new reserves during 1981 and 1982. Two depth records, one for drilling and one for production, were set by wells in the Delaware basin.

There has been exploration activity in the oil and gas frontier areas of the Permian basin. These areas include the Ouachita-Marathon folded belt in Presidio, Brewster, Pecos and Terrell Counties in west Texas and the Abo reef play in Chaves County, New Mexico, where some significant discoveries were made. Other areas include the Laramide folded belt in El Paso and Hudspeth Counties, Texas and the Marfa basin in Presidio, Jeff Davis and Brewster Counties. The Abo sands gas play in Chaves County, New Mexico has slowed due to a decrease in gas demand and the unsuccessful extension of production into Guadalupe and De Baca Counties. These and other frontier exploration areas will probably continue to attract seismic work and drilling in the future.

Table 13 — Area J-South. Permian Basin
(S.E. New Mexico, Chaves, Eddy, Lea & Roosevelt Cos.
and Texas RR Comm. Dists. 7C, 8 & 8A)
(trillion cubic feet)

	Probable	Possible	Speculative
Onshore (Drilling Depth)			
less than 15,000 feet	7	19	1
15,000 to 30,000 feet	8	14	—
Area J-South total	15	33	1

Area K: Alaska and Adjacent Offshore

Alaska has both production and potential; nowhere else is the hydrocarbon potential quite so high and land accessibility and environmental issues so large a problem. Alaska is a vast frontier area with 357 million acres on land and another 380 million acres between the shoreline and the 1,000-meter water depth. Only two areas have established oil production at the present time, the Cook Inlet basin west and southwest of Anchorage, and the North Slope. Only the Cook Inlet basin has gas production. One major problem for development of the natural gas resources of Alaska has been finding accumulations which are sufficiently large to justify completion and development of pipeline systems.

Alaska encompasses parts of the Rocky Mountain and Western North American Borderland tectonic and stratigraphic setting. Sedimentary rocks that produce or are considered prospective producing intervals are Paleozoic or younger. Structures are both folded and faulted. Reservoir rocks are variable lithologies from sandstones to carbonates.

Alaska is still in a frontier mode, but there are better interpretations now about both limits and potentials. Recent seismic work and wildcat drilling have diminished what was earlier considered to be prospective acreage, for example, portions of the Gulf of Alaska and the Lower Cook Inlet. Negative results of exploratory activity in the Kodiak and Yakataga areas have also resulted in reduction of estimates of potential gas resources. The only post-1975 wildcats drilled in the National Petroleum Reserve-Alaska (NPRA) were drilled by the U.S. Geological Survey. The NPRA is considered to contain potential for development of gas resources. There are a number of large areas like the Bering Sea, Arctic Wildlife Refuge, Norton basin and Chukchi Sea that, as yet, have not been explored for oil or gas. These frontier areas hold unknown hydrocarbon potential as could portions of such already partially drilled areas as the Arctic and Cook Inlet basins.

Estimates of the Probable and Possible resources for Alaska remain the same in 1982 as for 1980. However, there has been a reduction of 11 Tcf in the estimate of Speculative resources. This reduction is due largely to better definition of the basins in the Bering Sea area. Recent work has shown that these are continental margin basins and are more limited in areal extent than previously considered. These recent data have, therefore, caused Committee members to be less optimistic about the resources of the total Bering Sea area.

Portions of the Arctic National Wildlife Refuge are looked upon by industry as among the more promising areas in Alaska with respect to prospects for future oil and gas resources. Because of limitations on available data for the Wildlife Refuge and present restrictions on exploration activities, the magnitude of the potential natural gas resource is not yet clearly known. Federal guidelines for exploration and development are not likely before 1986. Therefore, the timing of lease offerings is uncertain.

A better understanding of some of the frontier areas hopefully may be developed through exploration and drilling in the next several years. Areas in which there is present and planned exploration and drilling include the Norton basin, the St. George basin, the Navarin basin, the Lower Cook Inlet, and the Yakutat block in the eastern Gulf of Alaska. Active drilling is presently going on in the Yakutat block. Drilling should commence within one or two years in the St. George basin, the Norton basin, and the Lower Cook Inlet.

Table 14 — Area K. Alaska and adjacent offshore
(trillion cubic feet)

	Probable	Possible	Speculative
Onshore (Drilling Depth)			
less than 15,000 feet	6	16	28
15,000 to 30,000 feet	—	—	—
Total	6	16	28
Offshore (Water Depth)			
less than 200 meters	2	13	59
200 to 1,000 meters	—	—	10
Total	2	13	69
Area K total	8	29	97

Area L: California, Nevada, Pacific Northwest (excluding Idaho), and Adjacent Offshore

Area L includes the Pacific Coast states, onshore and offshore, and the State of Nevada. Onshore, major production comes from the Great Valley, but onshore portions of the Ventura basin and the Los Angeles basin are also quite important. Elsewhere, Area L has seen exploration and recently developed production in northwest Oregon in the Astoria-Nehalem basin. Other parts of Oregon and Washington have been the sites of increased exploration, but no production has been established. There is limited oil production from Nevada, but no significant gas production. The principal sedimentary basins which have been the sites of exploration and production are all located in California and include the largely gas-prone Sacramento basin which lies in the northern part of the Great Valley as well as the more oil-prone San Joaquin basin (southern part of the Great Valley), Ventura and other coastal basins, Los Angeles basin and the offshore areas.

During Mesozoic time orogenic deformation of the west coast of North America formed chains of volcanos and fault-block basins and floods of both clastic and volcanic sediments were deposited on what became much of Area L. Later tectonic activity and subsequent erosion formed a complex of faulted mountain ranges and deep valleys which comprise Nevada and southern Arizona.

The California basins received thick accumulations of sediments during Cretaceous and Tertiary time which were deposited in deep to shallow marine environments and which contained abundant organic remains which have been converted to hydrocarbons. Surface seepage of these hydrocarbons controlled early exploration programs. California production, offshore and onshore, comes mostly from Cenozoic sandstones associated with traps that are structurally complex.

There was a decrease in the estimates of potential supply in all categories for the onshore portion of Area L. The primary reason for this decrease was a re-evaluation of the estimate for the San Joaquin Valley. Since the first report was made in 1966, the estimates for the San Joaquin Valley have been high, relative to other portions of Area L, and the results of deeper drilling in the past 16 years have been a disappointment in the San Joaquin Valley. Since gas production in the San Joaquin Valley has been dominantly associated gas, the former potential supply estimates would have required discovery of oil in quantities that now seem unreasonably high for this basin.

Exploration for natural gas in the onshore portion of Area L continued at relatively low levels except for the Sacramento Valley where many extensions and smaller new field discoveries were made in the past two years, but no new fields of significant size were discovered. Renewed interest in developing production from the lenticular sands in the Forbes Formation has met with success in many areas of the Sacramento basin. Many productive horizons and a wide range of trapping mechanisms continue to make the Sacramento Valley an attractive area for exploration, though activity in 1982 was down slightly from 1981.

In the San Joaquin Valley, associated gas from the new field discovery at Tulare Lake and from many smaller developments in the Stevens sands in Kern County have been the most significant events in that basin for the past two years.

In the Ventura-Coastal areas of onshore California, there were several extensions and a new field discovery at Los Alamos giving this area a better rate of success than that seen in recent years; the gas is solution gas in association with oil production.

Two new gas pools for the Mist Field in Oregon and subcommercial quantities of gas from two wells in Washington continue to give encouragement for continued exploration in the Pacific Northwest, though results during the past two years have not measured up to the high level of optimism that existed after the initial discovery of gas at Mist in 1979.

Offshore activity increased significantly over the previous two-year period. Central California OCS Sale #53 was held in May 1981 and Southern California OCS Sale #68 was held in June 1982. High bids on 251 tracts offered totaled 2.43 billion dollars. Sale #53 was marked as having the largest bonus ever offered in the United States for one tract, 33.6 million dollars. OCS Sale #73, Central and Northern California, is scheduled for late 1983.

Discovery of a major oil field off Point Arguello in the southern Santa Maria area was announced. Additional new pool discoveries were also announced in the Santa Barbara Channel area. Considerable drilling activity is underway in the Santa Maria-Point Arguello area and the State of California has announced a sale in late 1983, the first state sale since 1968. The Probable and Possible resource category estimates increased as a result of the discoveries near Point Arguello.

Table 15 — Area L. California, Nevada, Pacific Northwest
and adjacent offshore
(trillion cubic feet)

	Probable	Possible	Speculative
Onshore (Drilling Depth)			
less than 15,000 feet	1	6	7
15,000 to 30,000 feet	1	2	1
Total	2	8	8
Offshore (Water Depth)			
less than 200 meters	—	5	4
200 to 1,000 meters	—	4	5
Total	—	9	9
Area L total	2	17	17

Natural Gas From Low Permeability Formations

For this report, members of the Area Work Committees of the Potential Gas Committee were asked to estimate the quantity of potential gas resources which might exist in formations which have in-situ permeabilities to natural gas of less than 0.1 millidarcy and which are included in the Committee's overall resource assessments. In order to make the estimates of "tight" formation resources, Committee members relied on extrapolation of known formation characteristics from current producing areas, on permeability data from cores taken in wildcat wells outside current producing areas, and on analogy of prospective regions to explored regions. Because of the many uncertainties involved in extrapolation of formation characteristics to unexplored provinces and depths, the estimates of the resource contained in low permeability formations are subject to considerable uncertainty. Therefore, the estimates presented in table 16 are to be considered only as approximate but representing the magnitude of the resource. All estimates are presented as percentages of the total resource potential. No resources from low permeability formations are included in the estimates for offshore areas or for Area K (Alaska).

In Retrospect and Prospect

As for all resources occurring in the crust of the earth, the absolute volume of natural gas ultimately recoverable is a specific but unknown quantity. It should be recognized that changes in estimates of the potential supplies from time to time do not actually increase or decrease the ultimately recoverable volume. Such changes reflect improvements in estimating techniques and increased basic knowledge of the occurrence of natural gas at the time of the estimate. It must also be recognized that any estimate of potential supply lacks the accuracy of the estimates of proved recoverable reserves.

Economic, technological and governmental factors do not change the absolute volume of ultimately recoverable natural gas. Such factors, however, do influence the estimates of the potential supply in that they may increase or decrease the amount of gas which the estimator feels are within the limits of economic and technological feasibility. These factors may further influence the timing and rate of development of natural gas resources.

In each succeeding study by the Potential Gas Committee, the impact of new technology has been considered. In the first study of 1964, offshore drilling was limited to

Table 16 — Potential natural gas resources in tight formations

Estimated percentage of natural gas potential occurring in formations
with less than 0.1 millidarcy relative permeability to gas

	PROBABLE				POSSIBLE				SPECULATIVE			
	0 - 15,000 ft.		15,000 - 30,000 ft.		0 - 15,000 ft.		15,000 - 30,000 ft.		0 - 15,000 ft.		15,000 - 30,000 ft.	
AREA - Onshore	Total Potential (Tcf)	Amount in Tight Fms. (%)	Total Potential (Tcf)	Amount in Tight Fms. (%)	Total Potential (Tcf)	Amount in Tight Fms. (%)	Total Potential (Tcf)	Amount in Tight Fms. (%)	Total Potential (Tcf)	Amount in Tight Fms. (%)	Total Potential (Tcf)	Amount in Tight Fms. (%)
A	27	87%	—	—	8	5%	—	—	22	—	11	—
B	4	8%	2	9%	3	8%	3	10%	3	10%	4	12%
C	—	—	—	—	2	—	—	—	1	—	—	—
D	8	10%	—	—	20	15%	—	—	15	20%	4	20%
E	3	—	3	—	4	—	11	—	—	—	—	—
G	7	4%	5	6%	9	6%	6	8%	2	6%	2	8%
H	29	75%	20	25%	37	39%	56	26%	26	27%	40	73%
I	2	47%	—	—	3	11%	—	—	1	—	—	—
J-North	15	--	9	22%	22	5%	38	37%	5	60%	34	59%
J-South	7	7%	8	—	19	2%	14	—	1	—	—	—
L	1	4%	1	30%	6	5%	2	30%	7	10%	1	40%
Total Onshore Lower 48 States	151 Tcf 37%				263 Tcf 19%				179 Tcf 30%			

water depths of 300 feet. In 1966, this limit was increased to 600 feet, and in 1968, the water depth was increased further to 1,500 feet. Drilling depths were increased also, from 25,000 to 30,000 feet, in the 1968 report. The parameters of maximum drilling depth of 30,000 feet and 1,500 feet water depth were used for the 1970, 1972, and 1976 reports. The parameters for the 1978, 1980, and 1982 publications retain the onshore maximum drilling depth of 30,000 feet. In offshore areas, separate estimates are made for resource potential existing beneath water depths of 0 to 200 meters (656 feet) and 200 to 1,000 meters (3,281 feet). All potential supply estimates represent most likely volumes. The effects of newly developed technology will continue to be considered in future studies.

Table 17 summarizes the estimates of potential supply which have been given in each of the Potential Gas Committee reports.

Table 17 — Comparison of estimates of potential supply of natural gas from Potential Gas Committee reports (trillions of cubic feet at 14.73 psia and 60° F.)

	Probable	Possible	Speculative	Total
Lower 48 States				
As of 12-31-66	300	210	180	690
As of 12-31-68	238	317	245	800
As of 12-31-70	218	326	307	851
As of 12-31-72	212	290	278	780
As of 12-31-76	192	318	188 to 238	698 to 748
As of 12-31-78	186	359	285	830
As of 12-31-80	185	329	254	768
As of 12-31-82	184	326	232	742
Total United States (including Alaska)				
As of 12-31-68	260	335	632	1,227
As of 12-31-70	257	387	534	1,178
As of 12-31-72	266	384	496	1,146
As of 12-31-76	215	363	345 to 395	923 to 973
As of 12-31-78	199	399	421	1,019
As of 12-31-80	193	358	362	913
As of 12-31-82	192	355	329	876

Table 18 — Estimated potential supply of natural gas
in United States as of December 31, 1982
Onshore, 0-15,000 feet drilling depth
(trillions of cubic feet at 14.73 psia and 60° F.)

Area	Probable	Possible	Speculative
A	27	8	22
B	4	3	3
C	—	2	1
D	8	20	15
E	3	4	—
G	7	9	2
H	29	37	26
I	2	3	1
J-North	15	22	5
J-South	7	19	1
L	1	6	7
48 States Subtotal	103	133	83
K Alaska	6	16	28
Total less than 15,000 feet Drilling Depth Onshore United States	109	149	111

Table 19 — Estimated potential supply of natural gas
in United States as of December 31, 1982
Onshore, 15,000-30,000 feet drilling depth
(trillions of cubic feet at 14.73 psia and 60° F.)

Area	Probable	Possible	Speculative
A	—	—	11
B	2	3	4
C	—	—	—
D	—	—	4
E	3	11	—
G	5	6	2
H	20	56	40
I	—	—	—
J-North	9	38	34
J-South	8	14	—
L	1	2	1
48 States Subtotal	48	130	96
K Alaska	—	—	—
Total 15,000 to 30,000 feet Drilling Depth Onshore United States	48	130	96

Table 20 — Estimated potential supply of natural gas in United States as of December 31, 1982
Offshore, 0-200 meters water depth
(trillions of cubic feet at 14.73 psia and 60° F.)

Area	Probable	Possible	Speculative
A	—	—	11
B	1	2	15
C	—	—	—
D	—	—	—
E	20	23	—
G	9	11	—
H	—	—	—
I	—	—	—
J-North	—	—	—
J-South	—	—	—
L	—	5	4
48 States Subtotal	30	41	30
K Alaska	2	13	59
Total less than 200 meters Water Depth Offshore United States	32	54	89

Table 21 — Estimated potential supply of natural gas in United States as of December 31, 1982
Offshore, 200-1,000 meters water depth
(trillions of cubic feet at 14.73 psia and 60° F.)

Area	Probable	Possible	Speculative
A	—	—	5
B	—	—	13
C	—	—	—
D	—	—	—
E	1	13	—
G	2	5	—
H	—	—	—
I	—	—	—
J-North	—	—	—
J-South	—	—	—
L	—	4	5
48 States Subtotal	3	22	23
K Alaska	—	—	10
Total 200 to 1000 meters Water Depth Offshore United States	3	22	33

PART II

REPORT OF THE POTENTIAL GAS AGENCY

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REPORT OF THE POTENTIAL GAS AGENCY

Evaluation by Potential Gas Agency

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The accompanying report by the Potential Gas Committee (PGC) is the ninth estimate of the potential supply of natural gas in the United States made by the Committee and the eighth published by the Potential Gas Agency (PGA) of the Colorado School of Mines. The estimates contained in this report have been prepared by members of the Potential Gas Committee working through their Area Work Committees and reviewed at the regional and national level by the entire Potential Gas Committee. The Potential Gas Agency has acted to guide and assist the work of the Potential Gas Committee and to assure that professional standards and objectivity were maintained during the preparation of the estimates.

DUTIES AND RESPONSIBILITIES OF POTENTIAL GAS AGENCY

The Potential Gas Agency is charged with approving the criteria and methods used by the Potential Gas Committee and insuring that these are followed and maintained in preparing estimates and reports; the object being to maintain the highest scientific standards and objectivity. The Agency also acts to assure that there is an adequate representation of qualified personnel from many different segments of the natural gas industry and governmental and academic sectors. The Agency appoints the Chairman and Regional Vice Chairmen of the Potential Gas Committee and approves the appointment of other members to the Committee.

The Agency is sponsored by the American Gas Association through a grant to the Colorado School of Mines. The School of Mines, in turn, is responsible for selecting the Director and other personnel of the Agency and conducting the affairs of the Agency in a professional manner. Guidance for the PGA is provided by the Gas Supply Committee of the American Gas Association, which is responsible for the setting of general policy and objectives and financing of the study.

ORGANIZATION AND OPERATION OF POTENTIAL GAS COMMITTEE

There is no direct link between the Gas Supply Committee of the American Gas Association and the Potential Gas Committee. All contact is through the Potential Gas Agency. One of the duties of the Agency is to see that separation is maintained. The significance of this separation is that the Gas Supply Committee does not, in any way, enter into the deliberations nor influence the estimates which are prepared by the PGC.

Membership of the Potential Gas Committee is drawn from both large and small exploration and production companies, consultants, state geological surveys and academic institutions. Most of the members are geologists and engineers. Observers from a number of Federal agencies and various associations are also included in the Committee membership. For administrative purposes, the United States is divided into three regions (East, Central and West) and into 12 Work Areas. Each of the Work Areas has a Chairman, whose appointment must be approved by the Potential Gas Agency, and who reports to a Regional Vice Chairman. The Area Work Committees must also include at least one representative each from the pipeline and distribution segments of the natural gas industry in order to assure broad representation of all interests.

Each Area Work Committee functions independently. Its members are charged with gathering all available information about the geology and occurrence of natural gas in the assigned area. The members review past exploration and production history and, based on the historic record and their collective geological and operating expertise, evaluate the potential for further discoveries in both partially explored and unexplored basins.

The procedures for arriving at the estimates of potential supply are outlined in detail in Part I of this report. The

Director and other staff members of the Potential Gas Agency have met with Area Work Committees and have observed their operation. It is the conclusion of the Agency that the Area Work Committees have followed the standards adopted by the Potential Gas Committee, as outlined in Part I, in preparing their estimates.

Because of the nature of the work involved, it is not always possible to achieve complete uniformity in the work of all of the Area Committees. In some areas, there is a great deal of geologic knowledge and the area is in a reasonably mature stage of exploration. In other areas, exploration has only begun and there is relatively little basic geologic information. In spite of these differences, in the opinion of the Potential Gas Agency, the work of the Committee has been conducted in a sound and scientific manner.

Although the only way in which the estimates of the Committee can be proved or tested is by drilling prospective areas, the variety of background of individuals working on the Committee and the discussion and review which have occurred at both the area and national levels have resulted in a consensus. Over the past 19 years, several hundred qualified professionals have participated in the work of the Potential Gas Committee. The consistency of the results of these investigations within the parameters set by the Committee is notable. Although there may be differences of opinion as to the potential in limited local areas or basins, the resulting figures are reasonable estimates when reported as composite figures for Potential Gas Committee reporting areas.

REVIEW OF PROVED RESERVES AND POTENTIAL SUPPLY

As emphasized in the report of the Potential Gas Committee, the estimates presented by this Committee are of potential supply which is in addition to proved reserves. In order to gain a total perspective of the potential ultimately recoverable volume of natural gas in the United States, it is necessary to consider the total of cumulative past production, present proved reserves, and future supply. Cumulative natural gas production for each of the PGC reporting areas, taken from the published report of the Office of Oil and Gas, Energy Information Administration, U.S. Department of Energy as of December 31, 1981, is shown in figure 16. Also shown in figure 16 are estimates of proved natural gas reserves for each of the Potential Gas Committee reporting areas, based on estimates published by the U.S. Department of Energy, December 31, 1981. Estimates of cumulative production and proved reserves for year-end 1982 are not available at the date of publication.

The report of December 31, 1979 prepared by the Committee on Natural Gas Reserves of the American Gas Association was the last report prepared by that committee following the procedures of past years and published jointly with reports of the American Petroleum Institute and the Canadian Petroleum Association. In February 1980, the first of a new series of reports on U.S. Crude Oil and Natural Gas Reserves was issued by the Office of Oil and Gas Information System, Energy Information Administration, U.S. Department of Energy. This report compiled estimates of U.S. proved reserves of crude oil and natural gas based on data submitted to the Department by selected oil and gas well operators as of December 31, 1977. Subsequent reports cover the years 1979, 1980 and 1981. This series of reports by the Department of Energy replaces the reports of the American Gas Association and the American Petroleum Institute.

All subsequent comparisons between the PGC's estimate of potential supply as of December 31, 1982 and the cumulative production and proved reserves data as of December 31, 1981 must be made with difference in reporting dates in mind. Based upon Department of Energy data, cumulative production figures for 1982 are approximately 18 Tcf greater than those for 1981 presented here.

Estimates of ultimately recoverable volume, including the future potential estimated by the Potential Gas Committee plus past production and present proved reserves, have remained consistent considering the modifications to limiting parameters which have been made throughout the years. (See table 22.) The consistent total of ultimately recoverable volume reflects the fact that quantities of natural gas have been developed regularly from potential supply through exploration and drilling into proved reserves and ultimately into production. (Table 23 summarizes the ultimately recoverable volumes of natural gas in the United States by PGC reporting areas.)

Assuming that 1982 year-end proved reserves are equal to year-end 1981 (202 Tcf for total U.S. and 169 for the lower 48 states), the estimate of ultimately recoverable volume for the total United States is 1,711 Tcf and for the lower 48 states is 1,542 Tcf. Both of these estimates reflect the increase in proved reserves indicated in Department of Energy estimates for 1981, and are slightly higher than the estimates for year-end 1980. The estimate of potential supply reflects the net result of (1) transfers of volumes of natural gas from potential supply to proved reserves and production and (2) increases and decreases in estimates due to re-evaluation of the potential based on newly available geological, geophysical and engineering data. The net decrease in estimates for the total U.S. is 37 Tcf. This quantity is slightly more than the amount estimated to have been added to proved reserves through new field

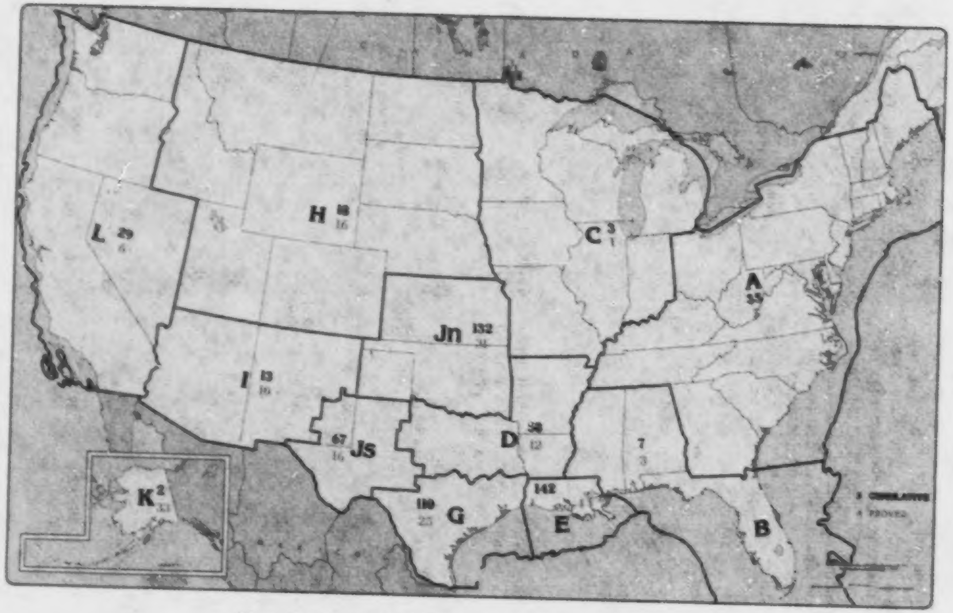
L 29 6
H 18 16
I 13 10
Jn 132 31
Js 67 16
G 110 25
E 142
D 38 12
C 3 1
A 35 3
7 3
B
K 2 33
CUMULATIVE
PROVED

Figure 16 — Geographic distribution of cumulative natural gas production and proved natural gas reserves as of December 31, 1981

and new pool discoveries and extensions over the past two years (1981 and 1982). When additions to proved reserves are accounted for, the net result of increases and decreases in estimates of potential resources is that there have been no substantial changes on a national basis. The estimates for individual areas have changed, however, and are summarized on a gross basis, combining all resource categories and depth intervals, in table 24.

The significant changes from 1980 to 1982 are:

Increases: Area H
Decreases: Areas G, J-North, K, and L.

Reasons for these changes are summarized in the repor of the Potential Gas Committee.

Table 22 — Comparison of estimates of ultimately recoverable volumes of natural gas in the United States for period December 31, 1966 to December 31, 1982 (trillions of cubic feet at 14.73 psia and 60° F.)

	(a)	(b)	(c)	(d)	(e)
	PREVIOUSLY DISCOVERED				
	Cumulative Production(1)(2)	Proved Reserves(1)(2)	Production plus Reserves (a + b)	POTENTIAL SUPPLY (total of Probable, Possible and Speculative categories)	ESTIMATE OF ULTIMATELY RECOVERABLE VOLUME (c + d)
Lower 48 States					
As of 12-31-66	307	286	593	690	1,283
As of 12-31-68	344	282	626	800	1,426
As of 12-31-70	387	260	647	851	1,498
As of 12-31-72	431	235	666	780	1,446
As of 12-31-76	514	184	698	698 to 748	1,396 to 1,446
As of 12-31-78	551	169	720	830	1,550
As of 12-31-80(2)	594	166	760	768	1,528
As of 12-31-82(2)	613*	169*	781*	742	1,523
Total United States**					
As of 12-31-68	345	287	632	1,227	1,859
As of 12-31-70	387	287	632	1,178	1,856
As of 12-31-72	432	266	698	1,146	1,844
As of 12-31-76	515	216	731	923 to 973	1,654 to 1,704
As of 12-31-78	553	200	753	1,019	1,772
As of 12-31-80(2)	596	199	795	913	1,708
As of 12-31-82(2)	615*	202*	817*	876	1,693

---

(1) Cumulative production and proved reserves estimates for 12-31-66 through 12-31-78 are estimates of the A.G.A. Committee on Natural Gas Reserves. Cumulative production figures reported for that period excluded gas in underground storage; the proved reserves figures included gas in underground storage.

(2) Cumulative production and proved reserves figures for 12-31-80 and 12-31-82 are estimated using data from the Office of Oil and Gas, DOE/EIA. Cumulative production figures include gas in underground storage; gas in underground storage is not included in proved reserves volumes.

*Cumulative production and proved reserves estimates are based on year-end 1981 data of the Office of Oil and Gas, DOE/EIA; 1982 data not available at the time of compilation. Cumulative production and proved reserves estimates do not add to table totals because of rounding.

**Alaska not estimated as of 12-31-66.

Table 23 — Summary of ultimately recoverable volumes of natural gas in the United States by geographic areas as of December 31, 1982*
(trillions of cubic feet at 14.73 psia and 60° F.)

	(a)	(b)	(c)		(d)		(e)
	PREVIOUSLY DISCOVERED — 1981			POTENTIAL SUPPLY — 1982			ESTIMATE OF ULTIMATELY RECOVERABLE VOLUME
Area	Cumulative Production*	Proved Reserves*	Production plus Reserves (a + b)	Probable	Possible	Speculative	(c + d)
A	35	5	40	27	8	49	124
B	7	3	10	7	8	35	60
C	3	1	4	—	2	1	7
D	58	12	70	8	20	19	117
E	142	44	186	27	51	—	264
G	110	25	135	23	31	4	193
H	18	16	34	49	93	66	242
I	13	10	23	2	3	1	29
J-North	132	31	163	24	60	39	286
J-South	67	16	83	15	33	1	132
L	29	6	35	2	17	17	71
Lower 48 States Subtotal	613**	169**	781**	184	336	232	1,523**
K-Alaska	2	33	35	8	29	97	169
Total United States	615**	202**	817**	192	355	329	1,693**

*Cumulative production and proved reserves estimates are year-end 1981 of the Office of Oil and Gas, DOE/EIA; 1982 data not available at the time of compilation.
**Area estimates do not add to national totals because of rounding.

Table 24 — Estimated potential supply of natural gas in the United States by geographic areas
(trillions of cubic feet at 14.73 psia and 60° F.)

Area	1976	1978	1980	1982
A	102	121(+19)	86(−35)	84(− 2)
B	51	53(+ 2)	54(+ 1)	50(− 4)
C	6	4(− 2)	3(− 1)	3
D	54	50(− 4)	51(+ 1)	47(− 4)
E	118	98(−20)	81(−17)	78(− 3)
G	93	85(− 8)	69(−16)	58(−11)
H	64	160(+96)	187(+27)	208(+21)
I	7	6(− 1)	6	6
J-North	107-157	143	135(− 8)	123(-12)
J-South	56	53(− 3)	51(− 2)	49(− 2)
K	225	189(−36)	145(−44)	134(−11)
L	40	57(+17)	45(−12)	36(− 9)
	923-973	1019(+60)	913(−105)	876(−37)

EXPLORATORY DRILLING, 1981 and 1982

In the years 1981 and 1982, exploratory drilling for gas and oil in the United States reached a record high level in terms of both the number of exploratory wells drilled and footage drilled.

Table 25 summarizes the number and footage of exploratory wells drilled for each of the years from 1972 through 1982. Estimates for the total number of exploratory wells drilled in the United States indicate that over 3,200 more exploratory wells were drilled in 1981 than were drilled in 1980 and approximately 1,300 more in 1982 than in 1981.

Exploratory drilling activity began to decrease sharply in the last half of 1982 in response to economic problems in the oil and gas industry and especially to decreased demand for natural gas. The level of activity in the first part of 1982 was sufficient, however, to result in a net increase in overall activity in 1982. All Potential Gas Committee areas except Areas B and K experienced an increase in both number of exploratory wells drilled and in total exploratory footage. Area B activity remained at about the same level of activity in 1982 as in 1980 while Area K experienced a decrease on the order of 50 percent. In several areas the average well depth decreased in spite of incentive pricing for gas below 15,000 feet. Total drilling activity, including both exploratory and development drilling, also increased markedly over the same time period (table 27).

Table 25 — Exploratory wells — total United States
(data from API Quarterly Review of Drilling Statistics)

	Number of Exploratory Wells Drilled	Footage	Average Well Depth
1972	7,539	45,043,798	5,975
1973	7,466	44,776,906	5,997
1974	8,619	50,261,744	5,832
1975	9,214	53,846,303	5,844
1976	9,234	52,812,406	5,719
1977	9,961	57,654,874	5,788
1978	10,677	63,234,745	5,923
1979	10,484	62,467,188	5,958
1980	11,916	69,948,320	5,870
1981	15,168	89,087,222	5,873
1982	16,470	95,587,432	5,804

Table 26 — Number of exploratory wells drilled, footage drilled, and average depth of wells — 1980 and 1982
(data from API Quarterly Review of Drilling Statistics)

	1980			1982		
Area	No. of Wells	Footage	Average Well Depth	No. of Wells	Footage	Average Well Depth
A	963	2,477,501	2,573	1,657	4,236,139	2,557
B	365	3,191,595	8,744	363	3,189,584	8,787
C	1,104	3,332,148	3,018	1,613	4,755,702	2,948
D	2,060	10,517,328	5,106	2,675	13,165,143	4,922
E	465	5,863,586	12,610	521	6,463,584	12,406
G	1,744	13,019,459	6,465	2,056	16,365,302	7,960
H	1,922	12,340,162	6,420	2,714	19,925,076	7,342
I	89	300,816	3,380	100	311,096	3,111
J-N	1,654	8,539,880	5,163	2,814	13,865,682	4,227
J-S	1,072	7,282,727	6,794	1,413	9,856,910	6,976
K	18	190,543	10,586	8	96,437	12,055
L	444	2,723,247	6,133	536	3,356,773	6,263
Total U.S.*	11,916	69,948,320	5,870	16,470	95,587,428	5,804

* Includes Gulf of Mexico-Northern

Table 27 — Drilling activity summary — 1973-1982
(data from API Quarterly Review of Drilling Statistics)

	Exploratory Wells		Total Wells	
	Number	Million Feet	Number	Million Feet
1973	7,466	44.8	26,592	136.4
1974	8,619	50.3	31,698	150.6
	15% increase over 1973		19% increase over 1973	
1975	9,214	53.8	37,235	174.4
	7% increase over 1974		17% increase over 1974	
	23% increase over 1973		40% increase over 1973	
1976	9,234	52.8	39,765	181.8
	1% increase over 1975		7% increase over 1975	
	24% increase over 1973		50% increase over 1973	
1977	9,961	57.7	46,479	215.0
	8% increase over 1976		17% increase over 1976	
	33% increase over 1973		75% increase over 1973	
1978	10,677	63.2	48,513	231.4
	7% increase over 1977		4% increase over 1977	
	43% increase over 1973		82% increase over 1973	
1979	10,484	62.5	51,263	243.2
	2% decrease over 1978		6% increase over 1978	
	40% increase over 1973		93% increase over 1973	
1980	11,916	69.9	62,462	288.9
	14% increase over 1979		22% increase over 1979	
	60% increase over 1973		135% increase over 1973	
1981	15,168	89.1	80,537	366.2
	27% increase over 1980		29% increase over 1980	
	103% increase over 1973		203% increase over 1973	
1982	16,470	95.6	88,106	401.4
	9% increase over 1981		9% increase over 1981	
	121% increase over 1973		231% increase over 1973	

PART III

POLICY GUIDELINES AND MEMBERSHIP OF THE POTENTIAL GAS AGENCY AND THE POTENTIAL GAS COMMITTEE

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POLICY GUIDELINES AND MEMBERSHIP OF THE POTENTIAL GAS AGENCY AND THE POTENTIAL GAS COMMITTEE

General Policy Statement

An appraisal of the long-range prospects of the natural gas industry in the United States — an appraisal that is useful for financial, managerial, and government purposes —requires, as an essential element, scientific, authoritative, and objective estimation of the potential supply of natural gas which may become available to the nation in addition to currently available proved recoverable reserves of natural gas.

The Potential Gas Committee fulfills this requirement by providing periodic estimates of the potential supply of natural gas which may become available. This Committee, together with its several Area Work Committees, is composed of about one hundred seventy individuals from the production, transmission, and distribution segments of the natural gas industry who are knowledgeable with respect to the potential supply of natural gas.

The quantities of natural gas included in this report by the Potential Gas Committee are only those which are considered to be recoverable by technology currently available or feasible in the foreseeable future. There are additional, potentially recoverable, quantities of natural gas contained in such situations as gaseous coal seams, geopressured zones, certain black shales, sandstones with very low permeability, and gas hydrates. Some workers have postulated large quantities of recoverable natural gas from each of these nonconventional sources, but there still remains considerable question as to the reasonable order of magnitude and the recoverability of this gas. These non-conventional sources largely have not been considered at this time by the Potential Gas Committee because the Committee feels that the technology of recovery has not yet been adequately demonstrated. As technological developments occur, the Committee will further study the potential from these sources and reconsider its estimates.

The Potential Gas Committee and its Area Work Committees discuss matters and data that are confidential. Fulfillment of the objectives of the Potential Gas Committee cannot be realized without the availability and utilizaton of information of a highly confidential nature. It is, therefore, the policy of the Potential Gas Committee and its Work Committees that every member, observer, and representative will respect such information and that there will be no disclosure of information or estimates, discussions, or other data, except as approved for release by the Potential Gas Committee.

A diagram of the organizational structure for the estimation of the potential supply of natural gas is shown in figure 17. A detailed description of the membership and duties of the several committees and of the Potential Gas Agency is presented in the sections which follow.

Membership of Committees and Policy Guidelines for Committees

The structure of the study of the potential supply of natural gas is divided into three parts consisting of the Gas Supply Committee of the American Gas Association, the Potential Gas Agency, and the Potential Gas Committee. The organization is shown graphically in figure 17.

GAS SUPPLY COMMITTEE
American Gas Association
William V. Holik, Jr., Chairman

Robert B. Kalisch, Staff Executive
Objectives, policy, agency selection, financing, industry liaison.

POTENTIAL GAS AGENCY
Colorado School of Mines

Mineral Resources Institute
Supported by the American Gas Association
Harry C. Kent, Director
Approve criteria and methods, insure maintenance of standards and objectivity, review and evaluate reports, publish final estimates of potential gas.

POTENTIAL GAS COMMITTEE
J. C. Herrington, Chairman
Merlin A. Johnson, Secretary
E. Floyd Humphries, Chairman, Executive Committee
George C. Grow, Jr., Chairman, Editorial Committee
Robert J. Cordell, Chairman, Committee on Definitions and Procedures
Richard J. Burgess, Chairman, Time and Site Committee

Under direction of Potential Gas Agency, outline study, establish criteria and methods, designate and instruct Work Committees, supervise, coordinate and compile estimates made by Work Committees.

Membership — (a) Chairman and Regional Vice Chairmen—appointed by Potential Gas Agency and approved by A.G.A. Gas Supply Committee.
(b) Each Work Committee Chairman.
(c) Potential Gas Agency — Director—Ex officio.
(d) Technical Advisors and Honorary Technical Advisors.
(e) Department of Energy, Energy Information Administration, Federal Energy Regulatory Commission, Department of Interior Geological Survey, Bureau of Mines, and such other governmental agencies as the Gas Supply Committee and Potential Gas Agency shall approve—one nonvoting observer each, and alternates, if desired.
(f) Gas Research Institute, Institute of Gas Technology, Natural Gas Supply Association, and Electric Power Research Institute—one nonvoting observer each, and alternates, if desired.
(g) Association of American State Geologists, NARUC, and IOCC—one nonvoting observer each, and alternates, if desired.
(h) Canadian and Mexican natural gas industry—one nonvoting observer each, and alternates, if desired.
(i) A.G.A., staff—one nonvoting observer.
(j) One Pipeline and one Distributor representative to be designated by the Gas Supply Committee.
(k) Others appointed by Gas Supply Committee and approved by Potential Gas Agency.

REGIONAL VICE CHAIRMEN
AND AREA WORK COMMITTEES

Number of committees and assignments as designated by Potential Gas Committee and approved by Potential Gas Agency.

Under direction of Potential Gas Committee, prepare estimates for given assignments.

Membership — (a) Chairman—appointed by Chairman of Potential Gas Committee and approved by Potential Gas Agency.
(b) Sufficient producer and other qualified members to insure proper representation for given assignment —appointed by Chairman of Work Area.
(c) At least one Pipeline and one Distributor representative to be designated by Gas Supply Committee.

WESTERN REGION Charles J. Crowley, Chairman		CENTRAL REGION James K. Curry, Chairman		EASTERN REGION Jeffery V. Morris, Chairman	
Area	Chairman	Area	Chairman	Area	Chairman
H	D. Keith Murray	C	Curtis L. Lundy	A	Porter J. Brown
I	Robert D. Habbit	D	Billy D. Brown	B	Billy C. Cook
K	Alexander Sisson	J-N	Alan F. Chatfield	E	Charles R. Brammell
L	William F. Edmondson	J-S	Louis F. Marczynski	G	John C. Kucewicz, Jr.

Figure 17 — Organization of Potential Gas Supply Studies

GAS SUPPLY COMMITTEE OF THE AMERICAN GAS ASSOCIATION

The membership of the Gas Supply Committee consists of representatives of member companies of the American Gas Association selected by the Chairman of the Board and approved by the Board of Directors of the American Gas Association.

The scope of the Committee is to coordinate, motivate, and make recommendations to the Board of American Gas Association as to the areas in which A.G.A should become more active in the development of adequate gas supply for both short-term and long-term. In addition, the Committee undertakes special projects, where necessary, to evaluate industry gas supply programs. The Gas Supply Committee oversees the work of the Potential Gas Agency.

The primary duties and responsibilities of the Gas Supply Committee with relation to potential gas studies include the following:

a. Establishing policy and objectives.
b. Providing required financial support.
c. Maintaining liaison with industry and industry organizations.
d. Selecting the Potential Gas Agency.
e. Approving the appointment of the Chairman and Regional Vice Chairmen of the Potential Gas Committee by the Potential Gas Agency.
f. Appointing pipeline and distributor representatives to the Potential Gas Committee as may be necessary or advisable.
g. Appointing such other members and observers to the Potential Gas Committee as may be necessary or advisable.
h. Assisting in procurement of qualified manpower to staff properly the Potential Gas Committee and the Area Work Committees.

The Gas Supply Committee of the American Gas Association takes no part in the work or the deliberations of the Potential Gas Committee or its sub-committees. The Gas Supply Committee does not participate in the studies leading to the estimates of potential supply of natural gas, and it neither approves nor disapproves the definitions and procedures, the estimates, or the report.

POTENTIAL GAS AGENCY OF THE COLORADO SCHOOL OF MINES

The Potential Gas Agency functions under the direction of the Vice President for Academic Affairs of the Colorado School of Mines. The School, with the approval of the Gas Supply Committee, appoints staff personnel to the Potential Gas Agency.

The Potential Gas Agency is supported by the American Gas Association. The American Gas Association is free, however, to take independent views of the operations and the studies produced by the Agency and its committees. The Agency is charged with the maintenance of scientific standards and objectivity of studies, and publishes the reports of the Potential Gas Committee. The Agency appoints the Chairman and Regional Vice Chairmen of the Potential Gas Committee, approves the appointment of members, representatives and observers to the Potential Gas Committee, and the chairmen of all sub-committees.

The Potential Gas Agency includes the following:

a. A Director, appointed by and responsible to the Colorado School of Mines.
b. Such additional staff personnel as may be required.
c. Members of the faculty of the Colorado School of Mines or other qualified individuals who may, from time to time, provide such professional services as the Director of the Potential Gas Agency and the Chairman of the Potential Gas Committee may determine necessary or desirable for discharging the duties of the Potential Gas Agency and the Potential Gas Committee.

The primary duties and responsibilities of the Potential Gas Agency include the following:

a. Approving criteria and methods established by Potential Gas Committee, including protecting the confidentiality of Potential Gas Committee data.
b. Insuring maintenance of the highest scientific standards and objectivity in Potential Gas Committee studies and reports.
c. Reviewing and evaluating reports prepared by the Potential Gas Committee.
d. Publishing, distributing, and publicizing reports of final estimates and other pertinent reports prepared by the Potential Gas Committee so as to assure the widest possible distribution and to promote understanding of them.
e. Further develop mutual understanding among the segments of the gas industry by helping the Gas Supply Committee unite the industry behind the potential gas studies.

f. Help improve industry-government relations in the public interest looking toward maximum acceptance and usefulness of potential gas studies.
g. Fulfill the professional obligation to publish technical papers concerning new techniques and knowledge gained.
h. Appointing Chairman and Vice Chairmen of Potential Gas Committee, with approval of Gas Supply Committee.
i. Approving appointment by Gas Supply Committee of other members, representatives and observers to the Potential Gas Committee.
j. Approving appointment of Chairman of Potential Gas Committee of Chairman of each Work Committee and chairmen of other committees.
k. Conduct the work of the Potential Gas Agency, in the public interest, in a manner which will enhance the stature of the Colorado School of Mines.
l. Adhere to the highest standards of objectivity.

The Colorado School of Mines may pursue other research, and individuals from the Agency may be involved in other research, consulting, and preparation and publication of papers in their professional fields, so long as these activities do not involve a conflict of interest nor invalidate the objectivity of the Agency.

POTENTIAL GAS COMMITTEE

The Potential Gas Committee comprises members, representatives, and observers from the producing, pipeline and distribution branches of the gas industry, together with observers from the American Gas Association, the Department of Energy, the Federal Energy Regulatory Commission, the U.S. Geological Survey, the National Association of Regulatory Utility Commissioners, the Interstate Oil Compact Commission, the Bureau of Mines, the Gas Research Institute, Institute of Gas Technology, Association of American State Geologists, Electric Power Research Institute, Natural Gas Supply Association and representatives from Canada.

The Chairman of the Potential Gas Committee is assisted by the three Regional Vice Chairmen and by an Executive Committee composed of senior members of the Potential Gas Committee, including past chairmen. It is the function of the Executive Committee to advise the Chairman on policy matters. An Editorial Committee is charged with approving the content of the report of the Potential Gas Committee.

The Definitions and Procedures Committee has the responsibility of reviewing and recommending to the membership of the Potential Gas Committee any proposed changes in the definitions and procedures used in the estimation of potential gas resources.

Membership of the Potential Gas Committee specifically includes the following:

a. Chairman of Potential Gas Committee.
b. Secretary of Potential Gas Committee.
c. Regional Vice Chairmen.
d. Chairman of each Area Work Committee.
e. Chairman of Executive Committee.
f. Chairman of Editorial Committee.
g. Chairman of Committee on Definitions and Procedures.
h. Chairman of Time and Site Committee.
i. Director of the Potential Gas Agency, ex officio.
j. Observer from the Federal Energy Regulatory Commission.
k. Observers from the Department of Energy.
l. Observer from the Geological Survey, United States Department of Interior.
m. Observer from the Bureau of Mines, United States Department of the Interior.
n. Observer from National Association of Regulatory Utility Commissioners.
o. Observer from the Interstate Oil Compact Commission.
p. Observer from Natural Gas Supply Association.
q. Observer from Association of American State Geologists.
r. Observer from the Gas Research Institute.
s. Observer from the Institute of Gas Technology.
t. Observer from Electric Power Research Institute.
u. Representative from the natural-gas pipeline industry.
v. Representative from the natural-gas distribution industry.
w. Observer representing the American Gas Association.
x. Observer from the Canadian natural gas industry and observer from the Mexican natural gas industry.
y. Technical Advisors and Honorary Technical Advisors.
z. Representatives and observers from other organizations may be recommended for appointment by the Potential Gas Agency Director and approved by the Gas Supply Committee.

All members of the Potential Gas Committee, except those specifically designated as observers, are considered as voting members of the Potential Gas Committee. Observers are invited and encouraged to participate in discussion of items brought before the Potential Gas Committee but do not have a vote in the determination of policy and procedure. Alternates to representatives and observers may be appointed.

Candidates for Committee Chairmen and Vice Chairmen normally will be geologists or persons with geology background from the academic community, pipelines, independent firms, gas utilities or producing companies. Retired or semi-retired gas industry people are not excluded from consideration.

Officers of the Potential Gas Committee and Area Work Committees are appointed as outlined in the Organizational Chart (fig. 17). Normally they serve for a period of one report. They are eligible for reappointment, however, for one additional report period. In calculating eligibility for reappointment, a partial term of office shall not be counted. This policy shall not operate to disqualify a member from longer service by reason of elevation in the organization. In other words, the two-term limitation shall apply to each position held, considering each membership or officership on a work committee or top committee as a separate position.

All officers, regional chairmen, and the pipeline and distributor representatives appointed by the American Gas Association Gas Supply Committee shall be subject to the two-report limit. Exceptions must be recommended by the appropriate Committee Chairman and the Potential Gas Agency Director, and approved by the American Gas Association Gas Supply Committee.

Technical Advisors include persons who have special knowledge of the occurrence of natural gas or the natural gas industry and whose expert advice will contribute to the successful performance of the Committee's assignments. Past Chairmen of Work Areas and Past Regional Vice Chairmen of the Potential Gas Committee will be appointed as Technical Advisors if they are willing to continue to participate in the work of the Committee. The appointment of Technical Advisors is approved by the Gas Supply Committee upon recommendation by the Potential Gas Agency Director. Technical Advisors are appointed for the preparation of a specific PGC report. Their appointment may be continued indefinitely but is subject to review and approval at the time of organization of the Potential Gas Committee for each succeeding report.

The designation of Honorary Technical Advisor may be given to such persons as have performed exceptional service to the Potential Gas Committee and whose continued participation and advice are desirable for the continued successful operation of the Committee. Honorary Technical Advisors are permanent voting members; their appointment is recommended by the Executive Committee and approved by the Potential Gas Agency Director and the Gas Supply Committee.

Observers from sponsoring associations, governmental agencies, and other cooperating groups serve at the discretion of these organizations and are not subject to the two-report policy.

The primary duties and responsibilities of the Potential Gas Committee include the following:

a. Outlining the scope and coverage of the estimates of potential natural gas supply.
b. Establishing criteria and methods for estimation of potential natural gas supply and other pertinent studies.
c. Designating Work Areas and Special Projects.
d. Appointing the Chairman of each Area Work Committee (by action of Chairman of Potential Gas Committee).
e. Approving appointment of other members of each Area Work Committee who are appointed by the Chairman of each Area Work Committee (by action of Chairman of Potential Gas Committee).
f. Instructing Area Work Committees.
g. Supervising, coordinating, advising, reviewing, evaluating, approving, and compiling estimates and such other assignments as may be given to committees.
h. Preparing reports of final estimates and such other reports as may be pertinent.
i. Submitting reports of final estimates and other pertinent reports to the Potential Gas Agency and counseling with Director regarding publication and distribution of such report.

AREA WORK COMMITTEES

Twelve Area Work Committees are the backbone of the Potential Gas Committee. Each of the Work Committees has the responsibility of developing an estimate of the potential supply of natural gas in a particular part of the United States. Following the system long used by the petroleum industry, each Area Work Committee is assigned geologically significant areas (without specific regard to state lines) in which the Committee members have expert working knowledge. These Committee members with their fund of information (often confidential), are the source of knowledge and judgment for estimating the undiscovered gas supply in each area. Because geologic rather than geographic divisions are used, publication of estimates by individual states is not feasible.

The membership of Area Work Committees consists of employees and consultants associated with the producing, pipeline, and distribution segments of the gas industry — as well as qualified personnel from State and Federal Agencies and educational institutions.

For administrative purposes, the Area Work Committees are grouped together in three regions: Eastern, Central and Western. Each of these regions is supervised by a Regional Vice Chairman who coordinates activities of the Area Work Committees within his jurisdiction and works with the Potential Gas Comittee Chairman in order to assure that there is an open flow of communication in both directions, and that the established techniques for resource estimation are being followed by the Area Work Committees.

Membership of Area Work Committees includes the following:

a. Chairman of each Area Work Committee.
b. An appropriate number of qualified working members deemed necessary by the Chairman of each Work Committee to insure the most objective estimates of potential supply of natural gas in the respective area assigned. Work Committee members are individuals from the natural gas and oil industries and other individuals who are qualified by their knowledge and experience to make estimates of potential supply of natural gas. The individuals are selected for each area because they have a close, working knowledge in all aspects of natural gas exploration and production.
c. At least one qualified representative on each Area Work Committee from the natural gas pipeline industry, appointed by the Gas Supply Committee.
d. At least one qualified representative on each Area Work Committee from the natural gas distribution industry, appointed by the Gas Supply Committee. (This requirement is waived for the Area K, Alaska, Committee.)

The Chairman and Vice Chairman of each Area Work Committee are subject to the two-report limit. Exceptions must be recommended by the Regional Vice Chairman, approved by the Potential Gas Committee Chairman and the Potential Gas Agency Director, and reported to the Gas Supply Committee, and only after receiving a clearance letter from the member's employer.

Other members of the Area Work Committees, appointed by the Area Chairman, will normally participate in the preparation of two successive reports. Service beyond the preparation of two reports may be continued if necessary to maintain adequate expertise and continuity on the Area Work Committee. Continuation of service beyond two reports must be recommended by the Area Chairman and approved by the Regional Vice Chairman, the Potential Gas Committee Chairman, and the Potential Gas Agency Director.

The primary duties and responsibilities of Area Work Committees include the following:

a. Appointing appropriate number of qualified working members to insure proper representation of various sectors of the industry and objectivity for the best estimates of potential supply of natural gas for the assigned areas (by action of Chairman of each Area Work Committee).
b. Estimating quantity of potential supply of natural gas in working areas designated by the Potential Gas Committee pursuant to the guidelines and parameters established by the Potential Gas Committee and approved by the Potential Gas Agency, and such other studies as may be assigned by the Potential Gas Committee.
c. Performing such other assignments as may be made in the respective area assigned by the Potential Gas Committee regarding such estimate.

Each member of each Area Work Committee will submit his estimates of potential supply of natural gas and such other assignments as may be given to him in his assigned sub-area to the Chairman and other members of his committee for review, evaluation, and approval.

Since the type and quantity of available information upon which to base estimates of potential natural gas supply vary widely from area to area, the Area Work Committee members use varied approaches in making their estimates. Inasmuch as the individual members work with private information obtained on a confidential basis from many sources, their working papers are not revealed in detail to anyone, including other members of the same Area Work Committee or others in the Potential Gas Committee. Without such confidential information, the Potential Gas Committee could not perform its task; therefore, each member, observer, or representative of the Work Committees is aware of and must respect the confidential nature of the data made available to him and of the estimates and other assignments prepared or reviewed by the Area Work Committees and the Potential Gas Committee.

Standing Committees of the Potential Gas Committee

EXECUTIVE COMMITTEE

The Executive Committee shall serve as the administrative coordinating committee for the Potential Gas Committee. It shall consider and discuss any matters of policy which are brought to its attention and shall make recommendations to the Potential Gas Committee regarding changes in policy. It shall act on behalf of the Potential Gas Committee on matters of urgency which arise between regularly scheduled meetings of the Potential Gas Committee. It may also be empowered to act on behalf of the Potential Gas Committee on matters designated by the Potential Gas Committee. At such times as vacancies occur in the following offices, the Executive Committee shall either act as a nominating committee to recommend suitable candidates or appoint a nominating committee from among its membership: PGC Chairman, Regional Vice Chairmen, Secretary of the PGC, and Chairman of the Executive Committee.

Chairmen of PGC standing committees, with the exception of the Executive Committee, will be appointed by the PGC Chairman, subject to approval by the Executive Committee. All actions of the Executive Committee will be reported to the membership of the Potential Gas Committee at their next regularly scheduled meeting, and shall be subject to review and approval by the Potential Gas Committee.

Membership

Chairman, elected from the membership of the Potential Gas Committee by the voting members of the PGC at a regular meeting. Nominations for Chairman will be made by the Executive Committee and nominations will also be received from the floor. Normally, the Chairman will be elected at the fall meeting following publication of the biennial PGC report and will serve for two years. Vacancies will be filled by election at the next regular PGC meeting, following the same procedure and a Chairman so elected will serve for the remainder of the unexpired term. In the absence of the elected Chairman, the Chairman of the Potential Gas Committee will serve as Chairman of the Executive Committee.

The following ex officio voting members: PGC Chairman, PGC Regional Vice Chairmen, Secretary of the PGC, Potential Gas Agency Director, Chairmen of Standing Committees, representatives appointed to the PGC from the natural-gas pipeline and natural-gas distribution industries, representative from the Canadian gas industry, observer from the American Gas Association.

In addition, a maximum of 5 voting Technical Advisors may be appointed by the Potential Gas Committee Chairman, subject to approval by the Potential Gas Agency Director.

EDITORIAL COMMITTEE

The Editorial Committee will review and approve the editorial content and format of PGC reports. They will work closely with the Potential Gas Agency in the publication of all official publications of the Potential Gas Committee.

Membership

Chairman, appointed by the Potential Gas Committee Chairman, and approved by the Executive Committee. Four members of the Potential Gas Committee, appointed by the Editorial Committee Chairman, with approval of the PGC Chairman. PGC Chairman, ex officio; Potential Gas Agency Director, ex officio.

COMMITTEE ON DEFINITIONS AND PROCEDURES

This Committee has the responsibility of reviewing and recommending to the membership of the Potential Gas Committee any proposed changes in the definitions and procedures used in the estimation of potential gas resources. Proposals to be reviewed by this Committee may be submitted by any member of the Potential Gas Committee. The Committee will further review estimates of potential gas resources made by other organizations which come to the attention of the Committee and may, from time to time, as deemed appropriate, prepare publications dealing with the comparison of the work of the Potential Gas Committee with that of other organizations. The Committee on Definitions and Procedures will also serve as liaison with the U.S. Geological Survey Resource Appraisal Group and other such organizations as are involved in the work of estimation of potential gas resources.

Membership

Chairman, appointed by the PGC Chairman, and approved by the Executive Committee. Four members of the Potential Gas Committee, appointed by the Chairman of the Committee on Definitions and Procedures, with approval of the PGC Chairman. PGC Chairman, ex officio; PGA Director, ex officio.

TIME AND SITE COMMITTEE

This Committee will select an appropriate location and date for each national PGC meeting which will serve best the needs of the Committee. Once the site and date of each meeting have been selected by the Committee, the Potential Gas Agency will be charged with the responsibility of completing the arrangements for the meeting. The Time and Site Committee will also coordinate any regional meetings which are scheduled by Regional Vice Chairmen in order that the dates of such meetings shall not be in conflict.

Membership

Chairman, appointed by the PGC Chairman, and approved by the Executive Committee. Two members of the Potential Gas Committee, appointed by the Chairman of the Time and Site Committee, and approved by the PGC Chairman. Regional Vice Chairmen, ex officio; PGC Chairman, ex officio; PGA Director, ex officio.

Communications

COMMUNICATION BETWEEN COMMITTEES

The formal channel of communication shall be from the Area Work Committees to the Potential Gas Committee to the Potential Gas Agency to the American Gas Association Gas Supply Committee and vice versa.

PUBLIC COMMUNICATION

Members of the Potential Gas Agency, the Potential Gas Committee, and the Area Work Committees are encouraged to publicize and explain their work. These efforts should be limited to explaining the methodology used, comparative methodology, and the strengths and limitations of the work. When acting as spokesmen for the Committees, members shall refrain from interpreting study results in terms of national policy needs or required industry incentives. Members who are called upon to make talks and write papers on behalf of the Committee should submit texts to the Potential Gas Agency for comment and policy review.

MEMBERSHIP OF THE POTENTIAL GAS AGENCY AND POTENTIAL GAS COMMITTEE

POTENTIAL GAS AGENCY

Harry C. Kent, Director
Lee C. Gerhard, Associate Director
Ladine Rintoul, Administrative Assistant

POTENTIAL GAS COMMITTEE

J. C. Herrington, Chairman
Charles J. Crowley, Vice Chairman, Western Region
James K. Curry, Vice Chairman, Central Region
Jeffery V. Morris, Vice Chairman, Eastern Region
Merlin A. Johnson, Secretary

Executive Committee

E. Floyd Humphries, Chairman

Charles M. Allen
A. M. Derrick
Richard J. Murdy
E. A. Rassinier
ex officio:
Donald W. Axford

Richard J. Burgess
Robert J. Cordell
Charles J. Crowley
James K. Curry
George C. Grow, Jr.
J. C. Herrington
Merlin A. Johnson
Robert B. Kalisch

Harry C. Kent
Monty G. Martin (alt.)
Charles P. Moreton
Jeffery V. Morris
Charles L. Neumeyer
A. A. Wilkins (alt.)

Editorial Committee

George C. Grow, Jr., Chairman

Charles J. Crowley
A. M. Derrick
William E. Mantek
Charles L. Neumeyer
David A. Rochester

ex officio:
J. C. Herrington
Harry C. Kent

Committee on Definitions and Procedures

Robert J. Cordell, Chairman

Richard J. Burgess
Charles J. Crowley
Lucio A. D'Andrea
Donald E. Hallinger
David A. Rochester

John C. Sharer
C. W. Spencer
ex officio:
J. C. Herrington
Harry C. Kent

Time and Site Committee

Richard J. Burgess, Chairman

Charles J. Crowley
James K. Curry
Jeffery V. Morris

ex officio:
J. C. Herrington
Harry C. Kent

Area Work Committees

Area	*Chairman*	*Vice Chairman*
A	Porter J. Brown	Paul G. Freund
B	Billy C. Cook	John M. Richart
C	Curtis L. Lundy	John Avila
D	Billy D. Brown	—
E	Charles R. Brammell	John H. McElroy
G	John C. Kucewicz, Jr.	Bill C. Burkman
H	D. Keith Murray	C. Keith Fisher
I	Robert D. Habbit	Edward M. Allshouse
J-N	Alan F. Chatfield	Joe E. McGarrah
J-S	Louis F. Marczynski	C. K. McLaughlin
K	Alexander Sisson	—
L	William F. Edmondson	Kenneth E. Wainwright

Observers

Donald W. Axford, D. W. Axford & Associates Ltd. (Canada)
Ellis R. Boyd, Jr., Division of Reserves & Natural Gas (DOE/EIA)
Lucio A. D'Andrea, Division of Reserves & Natural Gas (DOE/EIA)
Gordon L. Dolton, U.S. Geological Survey
W. Timothy Dowd, Interstate Oil Compact Commission
Charles G. Groat, Association of American State Geologists
E. Bruce Hagen, National Assn. of Regulatory Utility Commissioners
Tommie C. Hillis, Federal Energy Regulatory Commission (alternate)
Robert B. Kalisch, American Gas Association
Gordon W. Koelling, Division of Reserves & Natural Gas (DOE/EIA)
Jeremy Platt, Electric Power Research Institute
Milton Searl, Electric Power Research Institute (alternate)
J. Glenn Seay, Institute of Gas Technology
John C. Sharer, Gas Research Institute
Wayne M. Thompson, Federal Energy Regulatory Commission
David O. Webb, Gas Research Institute (alternate)
A. A. Wilkins, TCPL Resources, Ltd. (Canada, alternate)
Victor Wulc, Natural Gas Supply Association

Representatives

Monty G. Martin — Pipelines (alternate)
Charles P. Moreton — Pipelines
Charles L. Neumeyer — Gas Distributors
Willis B. Wood, Jr. — Gas Distributors (designate)

Technical Advisors

Francis J. Barker
James A. Barlow, Jr.
E. Perry Bendler
William E. Bennett
Richard J. Burgess
Robert J. Cordell
A. M. Derrick
Robert W. Gallagher
Dan B. Grubb
Donald E. Hallinger
John D. Haun
E. Floyd Humphries
William E. Mantek
Paul Mounce
Michael J. Popovich
Charles E. Smith
Gordon K. Zareski

Honorary Technical Advisors

Charles M. Allen
B. Warren Beebe
Mark V. Burlingame (deceased)
George C. Grow, Jr.
John M. Hanley
Richard J. Murdy
E. A. Rassinier
Lyon F. Terry (deceased)

ALLEN, C. M. (9)+: Oil & Gas Consultant, Homasassa Springs, FL 1981-. Phillips Petrol. Co., Bartlesville, OK, employed in various capacities in the Exploration and Production Dept. 1944-81. Adv. Board to Dept. of Geol., Univ. KS 1973-76. Mem. Am. Assn. Petrol. Geol. (Comm. on Emergency Preparedness 1974-76, Comm. on U.S. Energy Outlook 1970-73), Fed. Power Comm. Natl. Gas Surv. (Gas Supply Task Force 1971-75). Has testified in numerous state conservation agency, state and federal courts, and Fed. Power Comm. proceedings (including all major area and national rate proceedings), and hearings before Senate and House Congressional Committees. (Honorary Technical Advisor.)

AXFORD, Donald W. (7): Pres., D.W. Axford & Associates, Consulting, Calgary, Canada 1978-. Director: Frio Oils Ltd., Strand Oil & Gas Ltd.; Rock Ore Mining, DB&K Oils Ltd., Pres. 1977-78. Petro-Canada Inc., Sr. V. Pres., Expl. & Dir.; Pan Arctic Oils Ltd., Dir. 1976-77. Mobil Oil Canada, V. Pres., Expl. & Dir. (Calgary) 1948-76. Mem. Am. Assn. Petrol. Geol. (Adv. Council, Energy Minerals Div. Tar Sands Councilor), Canadian Petrol. Geol., Geol. Assn. Canada, Prof. Engr. Alberta, Soc. Econ. Paleon. & Min. (CANADA — Chairman.)

BARKER, Francis J. (5): V. Pres., Nat. Gas & Gas Liquids Dept., Oil & Gas Div., Union Oil Co. of CA, Los Angeles, CA 1971-; Gen. Mgr. (Chicago) 1970-71; Mgr. Opr. (Midland) 1967-70; Mgr. Engr. (Thums-Long Beach Co.) 1965-67; Dist. Mgr. (Santa Maria) 1963-65; Mgr. Expl. (Canary Islands, Spain) 1960-63; Supt. (Coalinga) 1957-60; Engr. 1948. Mem. Am. Petrol. Inst., Am. Inst. Min. Engr., Am. Assn. Petrol. Geol., Gas Processors Assn. (Board of Dir.), Am. Gas Assn. (Steering Comm., Gas Supply).

BARLOW, James A. Jr. (4): V. Pres., Barlow & Haun, Inc., Casper, WY 1957-. Forest Oil Corp., Geol. 1953-57. Ohio Oil Co., Geol. 1952-53. Mem. Am. Assn. Petrol. Geol., Assn. Prof. Geol. Scientists, Geol. Soc. Am., Rocky Mtn. Assn. Geol., WY Geol. Assn., Independent Petrol. Assn. Mtn. States.

BEEBE, B.W. (9): Geol., Geophysicist & Energy Consultant, Tulsa, OK 1980-. Geol., Geophysicist & Energy Consultant (Boulder, CO) 1972-80. Millison & Beebe (Partner) 1969-72. M. M. & B., Inc., V. Pres. & Sec., 1964-72. Ind. Geol. and Geophysicist 1959-64. Keating Drlg. Co., V. Pres. and Dir. 1955-58. Manhart, Millison & Beebe (Partner) 1950-55. Anderson-Prichard Oil Corp., Expl. Mgr. 1947-50. Bay Petrol. Corp., Ch. Geol., Expl. Mgr. (organized expl. dept.); V. Pres. 1942-47. Lerke & Whorton, Assoc. Cons., 1939-41. British-American Oil Prod. Co., Div. Geol. 1938-39. Shell Petrol. Corp., Geol. and Asst. to V. Pres. Expl., 1935-38. KS Emergency Relief Comm., Geol. 1934. Mem. Am. Assn. Adv. Science (Fellow), Geol. Soc. Am. (Fellow), Am. Assn. Petrol. Geol. (Hon. mem., Mem. 9: Natural Gases of N.A. [ed.] 1968, Dist. Lecturer 1969-70), OK Geol. Soc. (Hon. mem.), Rocky Mtn. Assn. Geol. (Hon. mem.), Am. Arbitration Assn., Am. Gas Assn., Assn. Prof. Geol. Scientists, KS Geol. Soc., Oklahoma City Geol. Soc., Soc. Expl. Geophysicists, Soc. Ind. Prof. Earth Scientists, Soc. Petrol. Engr., Rocky Mtn. Nat. Gas Men's Assn. (Honorary Technical Advisor.)

BENDLER, E. Perry (9): Geol., Expl. & Dev., The East Ohio Gas Co., Cleveland, OH 1955-. Mem. Am. Assn. Petrol. Geol. (Comm. on Statistics of Drlg.), Assn. Prof. Geol. Scientists (Cert. #2473), No. OH Geol. Soc., OH Geol. Soc., OH O&G Assn.

BENNETT, William E. (9): Pres., Phoenix Hydrocarbon, Ltd., Charleston, WV 1979-; GASAMEX, Ltd., Pres. (Charleston, WV) 1977 and V. Pres.-Expl., Monitor Petrol. Corp., (NYC, Charleston, WV) 1976-; Geol./Geophysicist 1974-76. Monitor Resources Corp., NYC, Cons. 1976-. Lunsford Granite Materials, Elberton, GA, V. Pres. 1976-. United Fuel Gas Co., Sr. Geophysicist 1969-74, Geophysicist 1962-68. Geol. 1957-61. Mem. Am. Assn. Petrol. Geol., Assn. Prof. Geol. Scientists (Cert. #1642, Past Pres. WV Sec.), Soc. Expl. Geophysics, Ind. O&G Assn. WV, OH Geol. Soc., Appalachian Geol. Soc., Fed. Power Comm. Natl Gas Surv. (Tech. Adv. 1975-76), Am. Gas Assn. (Atl. Action Comm. 1974-75).

BOYD, Ellis R. Jr. (1): Office of Oil & Gas, Div. of Reserves & Nat. Gas, DOE/EIA, Washington, D.C.; Chief, Reserves and Prod. Branch Deputy Dir., Office of Oil & Gas Information System 1977-. Federal Power Comm., held various positions in Area Rate Div. including Deputy Dir., Planning & Develop. Div.; Bureau of Nat. Gas and Chief, Planning & Spec. Proj. Branch. Marathon Oil Co., various production engineering and supervisory posts, Gulf Coast area 1954-66. Mem. Soc. Petrol. Engrs.

BURGESS, Richard J. (7): President, Northern MI Expl. Co., Jackson, MI 1981-; Exec. V. Pres. 1980-81; V. Pres. 1967-80. Consumers Power Co., Exec. Dir. Expl. 1967-80; Expl. Supv. 1963-67. Panhandle Eastern Pipe Line Co., Geol. 1962. Plymouth Oil Co., Geol. 1960-61. Imperial Oil Ltd. (Canada), Geol. 1954-60. Mem. Am. Assn. Petrol. Geol. (CPG #462), Geol. Soc. Am., MI O&G Assn., MI Basin Geol. Soc., Ontario Petrol. Inst.

BURLINGAME, Mark V. (9): Burlingame Consultants, Bradenton, FL 1967-. Nat. Gas Pipeline Co. of Am., Planning, Construction & Opr. Pipeline System, Offshore and Onshore Expl. Programs, Gas Storage in Aquifer fms. (dev.), Sr. V. Pres. Opr. (ret.) 1930-67. Served the Dept. of Interior as natural gas operations consultant and as the U.S. representative observer to the United Nation's European Economic Committee's Gas Energy Committee, served on technical natural gas missions behind the Iron Curtain. Mem. Am. Assn. Petrol. Geol. (Cert.), Am. Gas Assn., Am. Geol. Inst., Assn. Ind. Pet. Geol., Am. Pet. Inst., So. Gas Assn. (Honorary Technical Advisor.) (Deceased.)

CORDELL, Robert J. (4): President, Cordell Reports Inc., Richardson, TX 1980-; Consultant (Dallas, TX) 1977-80. Suntech Inc., Sr. Prof. Scientist, Energy Tech. and Sciences Dept., Res. and Engr. Div. (Richardson, TX) 1975-77. Sun Oil Co., Research Scientist, Sr. Research Scientist 1970-75;

+Number in parenthesis following name indicates number of Potential Gas Committee reports in which member participated.

Sr. Sec. Mgr., Geol. Research 1963-70; Mgr. Geol. Research 1955-63; Research Paleontologist-Research Geol.-Sr. Research Geol. 1951-55. Mem. Am. Assn. Adv. Sci. (Fellow), Am. Assn. Petrol. Geol., Dallas Geol. Soc. (Hon. Life Mem.), Dallas Geophys. Soc., Geol. Soc. Am. (Fellow), Paleon. Soc., Soc. Econ. Paleon. and Mineralogists.

CROWLEY, Charles J. (5): Consulting Reservoir Geol., El Paso Natural Gas Co., El Paso, TX 1977-; Sr. Reservoir Geol. 1965-77. Hercules Powder Co., Supr. 1962-65. Consultant (WY & AZ) 1958-62. Forest Oil Corp., Area Geol. 1953-59. Marathon Oil Co. (OH Oil), Scout-Area Geol. (Billings and Casper) 1949-53. Mem. Am. Assn. Petrol. Geol., El Paso Geol. Soc., Soc. Mining Engr., Reg. Geol. (AZ).

CURRY, James K. (9): Geological Consultant, Denver, CO 1981-. Panhandle Eastern Pipe Line Co., Mgr. Rocky Mtn. Region (Denver, CO) 1975-81; Mgr. Expl. & Prod. (Pan Eastern Expl., Houston) 1973-75; Mgr. Expl., Mgr. Geol., Dist. Geol., Geol., Jr. Geol. (Liberal, KS) 1946-72. Mem. Am. Assn. Petrol. Geol., Soc. Petrol. Engr., Rocky Mtn. Assn. Geol., Assn. Ind. Petrol. Geol.

D'ANDREA, Lucio A. (5): Div. of Reserves & Nat. Gas, Energy Information Admin., U.S. Dept. of Energy, Washington, D.C. Experience of about 20 years in various aspects and activities of natural gas industry - production, transportation, distribution and alternate gas supplies. Mem. Soc. Petrol. Engrs., Soc. Military Engr.

DERRICK, A. M. (9): Sr. V. Pres., Marketing, Rates, Regulatory Affairs, Customer Relations, Gas Transportation & Exchange, El Paso Natural Gas Co., El Paso, TX 1977-; V. Pres. 1972-77; Asst. V. Pres. 1966-72; Mgr. Res. Engr. 1959-66; Asst. Mgr. Res. Engr. (Houston, TX) 1958-59; Sr. Res. Engr. 1953-57. Stanolind Oil & Gas Co., Res. Engr. Supr. (Midland, TX) 1951-53; Jr. Petrol. Engr. (Wink, TX) 1950-51, (Tulsa, OK) 1949-50, (Pampa, TX) 1947-48. Mem. Am. Assn. Petrol. Geol., Am. Inst. Min., Met. & Petrol. Engr.-SPE, Soc. Petrol. Eval. Engr.

DOLTON, Gordon L. (4): Proj. Chief, Resource Assessment Group-Domestic, Br. Oil and Gas Resources, U.S. Geological Survey, Denver, CO 1975-; Geol., Resource Appraisal Group 1974-75. Shell Oil Co., Staff Geol. (Houston) 1973-74; Staff head, Planning and Venture Development (Denver) 1963-66; Sr. Geol. (Okla. City) 1963-66; Geol. (WY) 1954-60. Shell Development Co., Research Geol. (Houston) 1960-63. Richfield Oil Corp., Geol. 1951-52. Mem. Am. Assn. Petrol. Geol., Geol. Soc. Am., Rocky Mtn. Assn. Geol.

DOWD, W. Timothy (3): Exec. Dir., Interstate Oil Compact Commission, Oklahoma City, OK. Involvement in a variety of governmental activities as either an observer or participant including Oklahoma House of Representatives and counsel to the Governor of Oklahoma. Mem. Am. Bar Assn., OK Bar Assn., Fed. Energy Bar Assn.

GALLAGHER, Robert W. (6): Consultant, Houston, TX 1981-. Southern Natural Gas Co., Mgr., Reserves and Deliverability (Houston, TX) 1967-81; Sr. Engr. 1962-67. Mem Am. Assn. Petrol. Geol.

GERHARD, Lee C. (1): Prof. Geol., Colorado School of Mines, Golden, CO and Assoc. Dir., Potential Gas Agency and Consultant, Gerhard and Associates 1982-. Supron Energy Corp. (Englewood, CO), Expl. Mgr. 1981-82. ND Geol. Survey, State Geol. & Dir. 1977-81; Asst. State Geol. 1975-77. Univ. ND, Chmn. and Prof. Geol. 1977-81; Assoc. Prof. Geol. 1975-77. West Indies Lab. and Fairleigh Dickinson Univ., Act. Dir. and Assoc. Prof. Geol. 1975; Asst. Dir. and Assoc. Prof. 1972-75. Univ. So. CO, Assoc. Prof. Geol. 1966-72. Sinclair Oil & Gas Co., Reg. Stratigrapher, 1965-66; Expl. Geol. 1964-65. Amerada Petrol. Corp., Party Chief 1962. Univ. KS, Inst. Geol., Asst. Inst. Geol., Teaching Fellow 1960-64. Mem. Am. Assn. Petrol. Geol., Am. Inst. Prof. Geol., Assn. Am. State Geol., CO Scient. Soc., Geol. Soc. Am., ND Geol. Soc., Rocky Mtn. Assn. Geol., Soc. Econ. Paleon. & Min.

GROAT, Charles G. (1): Dir. & State Geol., Assn. Am. State Geol., Baton, Rouge, LA.

GROW, George C. Jr. (9): Consulting Geol., Westfield, NJ 1974-. Transcontinental Gas Pipe Line Corp., Ch. Geol.-Eastern area (NJ) 1950-73. The Peoples Natural Gas Co., Jr. Geol. to Ch. Geol. (PA) 1939-50. Standard Oil Co. (NJ), Geol. (Venezuela) 1938-39. Mem. Am. Assn. Petrol. Geol. (Cert. #31, Treas. 1974-76, Adv. Council 1976-, Fndn. Dev. Coord. 1973-), Am. Inst. Min., Met. & Petrol. Engr., Assn. Prof. Geol. Scientists (Cert. #1774), Geol. Soc. Am. (Fellow), Pittsburgh Geol. Soc. (Past Pres.), Am. Gas Assn. (Comm. Underground Storage 1951-72, Chmn. 1960-61; Task Group on Gas Storage Statistics, Chmn. 1964-71), Am. Petrol. Inst., PA Oil & Gas Assn., Ind. Oil & Gas Assn. WV, Lamont-Doherty Geol. Observatory, Columbia Univ. (Adv. Council), Fed. Power Comm. Natl. Gas Surv. (Underground Storage Task Force 1972-73; Prospective Expl. & Development Task Force 1975-). (Honorary Technical Advisor.)

GRUBB, Dan B. (1): V. Pres., Gas Supply, Natural Gas Pipeline Co., Houston, TX 1979-; Asst. V. Pres. for Gas Expl. and Prod., Asst. Chief Engineer and other key engineering and operational posts 1962-79. Mem. Am. Gas Assn., Interstate Nat. Gas Assn. Am., Reg. Prof. Engr. (11 states).

HAGEN, E. Bruce (3): Commissioner, North Dakota Public Service Commission, Bismarck, ND 1961-, Deputy Motor Vehicle Registrar for North Dakota 1961. Farmer in Benson and Ramsey Counties in North Dakota 1956-. Mem. Mid-America Regulatory Comm., Natl. Assn. Reg. Util. Comm., Regional Energy Adv. Bd. of U.S. Dept. of Energy, Regulatory Council.

HALLINGER, Donald E. (8): Mgr. Expl., Pacific Lighting Gas Development Co., Los Angeles, CA 1977-; Sr. Geol. 1966-77. Mem. Am. Assn. Petrol. Geol. (Cert.), Assn. Prof. Geol. Scientists (Cert., Past Sec.-Treas.), Soc. Econ. Paleon. & Min.

HANLEY, John M. (7): Retired, Omaha, NB 1973-. Northern Nat. Gas Co., V. Pres.-Gas Supply Studies 1965-73; V. Pres.-Long Range Planning 1963-65; V. Pres.-Gas Supply 1950-63; Supt. Prod./Head Dept. 1942-50; Prod. Engr. 1936-42; Gas Field Supt. (KS) 1933-36. Mem. Am.

Assn. Petrol. Geol., Soc. Petrol. Engr., Am. Gas Assn. (Nat. Gas Reserves Comm. 1945-56; Chmn., Nat. Gas Prod. Comm. 1956), Natl. Petrol. Council (Comm. on U.S. Energy Outlook 1970-72), Fed. Power Comm. (Natl. Gas Surv., Gas Supply Task Force 1970-73), Adv. Comm. on Energy to Sec. Int. 1970-71. (Honorary Technical Advisor.)

HAUN, John D. (8): Prof. Petrol. Geol., Colorado School of Mines, Golden, CO 1955-. Barlow and Haun, Inc., Consultant 1957-. Petroleum Research Corp., V. Pres. 1952-57. Stanolind (Amoco), Geol. Party Ch. 1951-52. Mem. Am. Assn. Petrol. Geol. (Pres. 1979-80), Am. Geol. Inst. (V. Pres. 1980-81, Pres. 1981-82), Am. Inst. Prof. Geol. (Pres. 1976), Am. Petrol. Inst., Geochem. Soc., Geol. Soc. Am. (Fellow), Nat. Petrol. Council, Rocky Mtn. Assn. Geol. (Pres. 1968), Soc. Econ. Paleon. & Min., Commissioner, Colorado Oil and Gas Conservation Comm. 1977-.

HERRINGTON, J.C. (7): Mgr., Geol. Staff, ARCO Exploration Co., Dallas, TX 1981-; Mgr., Atlantic OCS Proj., Mgr., CO^2 Expl., Western Reg. 1978-80; Mgr. Expl. Permian Dist. (Midland, TX) 1973-78; Spec. Proj. & Dist. Geol. (Lafayette, LA) 1971-73; Dist. Geol. (Tyler, TX) 1962-71; Dist. Geol. (offshore LA) 1959-62; Area Geol. (Dallas, TX) 1959; Geol. & Sr. Geol. (So. LA) 1953-58; Oil Scout (MS-AL) 1952-53. Mem. Am. Assn. Petrol. Geol., W. TX Geol. Soc., Am. Gas Assn., Am. Petrol. Inst., NM Geol. Soc., Assn. Prof. Geol. Scientists, Dallas Geol. Soc., Rocky Mtn. Assn. Geol.

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KALISCH, Robert B. (4): Director, Gas Supply and Statistics, American Gas Association, Arlington, VA 1975-. U.S. Air Force assignments (including Off. Scientific Research, Science and Tech. Staff Officer and Dir., Ionospheric Physics Lab.) 1951-75. Mem. Inst. Elec. and Electronics Engr., Research Soc. Am., Prof. Engr. (MA).

KENT, Harry C. (4): Director, Potential Gas Agency, Colorado School of Mines, Golden, CO 1976-; Prof. Geol. 1969-, Head Geol. Dept. 1970-75, Act. Head, Geol. Dept. 1969-70, Assoc. Prof. Geol. 1967-69, Asst. Prof. Geol. 1964-67, Instructor Geol. 1956-64. The California Co., Geologist (FL & LA) 1953-56. Stanford Univ., Teaching Asst. 1953. Mem. Am. Assn. Petrol. Geol. (Cert. Petrol. Geol. #2485), Geol. Soc. Am. (Fellow), Rocky Mtn. Assn. Geol. (Ed., Colorado Geology 1978-80). Soc. Econ. Paleon. & Min.

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MARTIN, Monty G. (1) (alternate for Charles P. Moreton): V. Pres., Gas Reserves and Deliverability, Texas Gas Transmission Corp., Houston, TX 1954-. Southwest Natural, Geol. 1952-54. Texas Gas Transmission Corp., Geol. 1949-52. Carter Oil Co., Geol. 1946-49. Mem. Am. Assn. Petrol. Geol., Am. Inst. Prof. Geol., Houston Geol. Soc., Soc Petrol. Engrs.

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MOUNCE, Paul (8): Expl. Mgr., Petrosil Resources Inc., Dallas, TX 1980-. Ind. Petrol. Geol. 1978-80. Maynard Oil Co., Ch. Geol. 1974-78. Lone Star Gas Co., Staff & Corporate Development. Texas Pacific Oil Co., Dist. Geol. Fifteen Oil Co., Dist. Geol. Warren Petrol. Corp., Dist. Geol. Mem. Am. Assn. Petrol. Geol., Am. Inst. Min., Met. & Petrol. Engr.

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PLATT, Jeremy (1): Proj. Mgr. Energy Res. Program, Electric Power Research Inst., Palo Alto, CA 1974-. Mem. Am. Assn. Petrol. Geol. (Energy Min. Div., Comm. on Nuclear Minerals), Geol. Soc. Am.

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TERRY, Lyon F. (9): Ret., Ridgewood, NJ 1967-. Lehman Bros., Assoc. 1957-66; Chase Nat. Bank, V. Pres. & Gas Engr. 1937-57; Ralph E. Davis Engr. (NYC), V. Pres. 1927-37; ESSO (NJ), Gas Eval. Engr. 1925-27; O&G Engr. (OK) 1915-25. Mem. Soc. Petrol. Engr., Am. Gas Assn. (Nat. Gas Reserves Comm., organized and Chmn. 1944). (PGC organizer, first Chmn., Honorary Technical Advisor.) (Deceased.)

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ZARESKI, Gordon K. (2): Sr. V. Pres., H. Zinder & Assoc., Washington, DC 1979-. Department of Energy, Office of the Oil & Gas Information System, Director (Washington) 1977-79. Federal Power Comm., Bureau of Natl. Gas, Chief of Planning & Development (Washington) 1969-77. Mem. Am. Assn. Petrol. Geol., Geol. Soc. Washington, DC.

AREA A

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FREUND, Paul G. (9): Ch. Geol., The Peoples Nat. Gas Co., Pittsburgh, PA 1952-. State of PA, Engr. 1950-52. Mem. Am. Assn. Petrol. Geol., Am. Gas Assn., Pittsburgh Geol. Soc. (Past Pres.).

GROW, George C. Jr. (9): Consulting Geol., Westfield, NJ 1974-. Transcontinental Gas Pipe Line Corp., Ch. Geol.-Eastern Area (NJ) 1950-73; The Peoples Natural Gas Co., Jr. Geol. to Ch. Geol. (PA) 1939-50; Standard Oil Co. (NJ), Geol. (Venezuela) 1938-39. Mem. Am. Assn. Petrol. Geol. (Cert. #31, Treas. 1974-76, Adv. Council 1976-, Fndn. Dev. Coord. 1973-), Am. Inst. Min., Met. & Petrol Engr., Assn. Prof. Geol. Scientists (Cert. #1774), Geol. Soc. Am. (Fellow), Pittsburgh Geol. Soc. (Past Pres.), Am. Gas Assn. (Comm. Underground Storage 1951-73, Chmn. 1960-61; Task Group on Gas Storage Statistics, Chmn. 1964-71), Am. Petrol. Inst., PA Gas Assn., Lamont-Doherty Geol. Observatory, Columbia Univ. (Adv. Council), Fed. Power Comm. Natl. Gas Surv. (Underground Storage Task Force 1972-73; Prospective Expl. & Development Task Force 1975-).

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LEEPER, Wayne S. (3): V. Pres., Expl. & Geol., Keystone Energy Oil & Gas, Inc., Pittsburgh, PA 1982-. National Fuel Gas Supply Corp., Chief Geol. & Mgr., Expl. (Buffalo, NY) 1974-81. United Natural Gas Co. & The Sylvania Corp., Chief Geol. (Oil City, PA) 1969-74; Geol. 1961-69. Mem. Am. Assn. Petrol. Geol., Northern Appalachian Geol. Soc. (Pres. 1965-66), Am. Petrol. Inst. (Penn York Chapter), PA Oil, Gas & Min. Assn. (Bd. Dir. 1976-), Cert. Prof. Geol. Scient. (No. 4308).

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RAGSDALE, Tom R., (4): Sterling Drilling & Prod. Co., Inc., Charleston, WV 1981-. Ray Resources, Ch. Geol. 1973-81. Consolidated Gas Supply Corp., Devel. Geol. (Clarkburg, VA) 1966-73. McCullough Tool Co., Engr. Geol. 1962-66. Mem. Appalachian Geol. Soc. (Past V. Pres.).

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WIGAL, James M. (3): Dist. Expl. Mgr., Adobe Oil & Gas Corp., Pittsburgh, PA 1981-. Peoples Nat. Gas Co., Geol./Geophys./Explor. Mgr. 1975-81. Dept. of Energy/Bureau of Mines (Morgantown, WV) Geol. 1974-75. Mem. Am. Assn. Petrol. Geol., Soc. Econ. Paleon. & Min., Soc. Econ. Geol., SPWLA.

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COOK, Billy C. (4): Chief Geol., Holly Energy, Inc., New Orleans, LA 1981-. The Louisiana Land and Exploration Co. (New Orleans, LA) Geol. 1972-81. Chevron Oil Co., Dev. & Expl. Geol. 1967-72. Mem. Am. Assn.Petrol. Geol., MS Geol. Soc., New Orleans Geol. Soc., Soc. Econ. Paleon & Min.

RICHART, John M. (4): Dist. Expl. Geol., Union Oil Co. of CA, Jackson, MS 1975-. Pure Oil Co. (prior to merger with Union), Expl. Geol. (IL, MI and Appalachian Basins) 1969-75. Mem. Am. Assn. Petrol. Geol., Jackson Geophysical Soc., MS Geol. Soc.

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KELLER, Stanley J. (3): Geol., Petroleum Section, IN Geol. Survey, Bloomington, IN 1953-. Mem. Am. Petrol. Inst., IN-KY Geol. Soc., IN Geol. Soc.

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**MANTEK, William E. (6): Sr. Staff Geol., Northern Michigan Exploration Co., Jackson, MI 1976-. Consumers Power Co., Sr. Geol. 1965-76. MI Geol. Survey-Oil & Gas Sec. (Lansing, MI), Geol. 1956-65. Mem. Am. Assn. Petrol. Geol. (Cert. Petrol. Geol. #828), MI Basin Geol. Soc.

MEFFORD, Nace F. Jr. (8): V. Pres., Wallace Resources, Ltd., Houston, TX 1980-. Enterprise Petroleum (Houston, TX), Exec. V. Pres. 1979-. Patrick Petroleum Corp., V. Pres. & Mgr. Property Acquisition 1973-79; Div. Mgr. (OK, Rocky Mtns., N. TX) 1970-73. Ashland Oil, Mgr. Property Acquisition 1967-69; Div. Mgr. (OH, MI, Canada) 1964-67; Ch. Petrol. Engr. 1953-64; Field Geol. & Engr. (MI Basin) 1948-53. Mem. Soc. Petrol. Engrs. of Am. Inst. Min., Met. & Petrol. Engr., Soc. Petrol. Eval. Engr.

SATTERFIELD, Ira R. (1): Geol. & Chief of Oil & Gas/Subsurface Sect., MO Geol. Survey, Rolla, MO 1981-; Oil & Gas Geol. 1979-81; Stratigrapher & Areal Geol. 1967-79. Amoco Production, Expl. Geol. 1965-67. Mem. Am. Assn. Petrol. Geol., Assn. MO Geol.

AREA D

Billy D. Brown, Chairman

ANDERSON, Sherman (1): Ch. Geol., Moore McCormack Energy, Dallas, TX 1981-; Eastern Dist. Expl. Mgr. 1979-81. Jackson Exploration (Dallas, TX), Dist. Geol. 1979. Lear Petroleum (Dallas, TX), Area Geol. 1978-79. Universal Resources (Dallas, TX), Dist. Geol. 1978. Ensearch Exploration (Tyler, TX, Jackson, MS, Dallas, TX), Sr. Staff Geol., Dist. Geol., Geol. 1964-78. Diamond Shamrock (Amarillo, TX), Jr. Geol., Geol. 1955-64. Mem. Am. Assn. Petrol. Geol.

BROWN, Billy D. (2): Mgr., Gas Res. Engr. Dept., Lone Star Gas Co., Dallas, TX 1982-; Sr. Staff Petrol. Engr. 1974-82. Eppler, Guerin & Turner, Acct. Exec. 1967-74. Cornell Oil Co., Petrol. Engr. 1966-67. Texas Pacific Oil Co., Staff Petrol. Engr. 1962-66. Texas Pacific Coal & Oil Co., Petrol. Engr. 1953-62. Mem. Nat. Gas Soc. No. TX, Soc. Petrol. Engrs. of Am. Inst. Min., Met. & Petrol. Engr.

**BOYINGTON, Lowell D. (3): Prod. Engr., Arkansas Western Gas Co., Fayetteville, AR 1967-. Texaco Inc., Area Engr. (Kermit, TX) 1962-67. Mem. Reg. Petrol. Engr. AR, Soc. of Petrol. Engrs., Am. Inst. Min., Met. & Petrol. Engr.

BURGESS, Ferrell L. (8): Dist. Mgr., Pennzoil Prod. Co., Shreveport, LA 1980-; Domestic Region Exploitations Mgr. (Houston) 1978-80; Sr. Geol. 1975-78; Dist. Res. Dev. Mgr. 1970-74; Geol. 1967-69. Union Prod. Co., Geol. 1955-67. Mem. Am. Assn. Petrol. Geol., Am. Petrol. Inst., Shreveport Geol. Soc.

FEEMSTER, Lee T. Jr. (8): Geol. Consultant, Abilene, TX 1974-. Texas Pacific Oil Co., Expl. Geol. & Development Geol. 1955-74. Stanolind (Amoco), Expl. Geol. 1951-55. Mem. Am. Assn. Petrol. Geol., Abilene Geol. Soc., West Texas Geol. Soc.

GEARHART, Harry L. (1): Independent, Dallas, TX 1977-. Maynard Oil Co., V. Pres. Expl. (Dallas, TX) 1972-77. Lone Star Prod. Co., Dist. Geol. (Dallas, TX) 1970-72; Dist. Geol. (Tyler, TX) 1967-70; Geol. 1961-67; Geol. (Shreveport, LA) 1958-61. Mem. Am. Assn. Petrol. Geol., East TX Geol. Soc.

MOUNCE, Paul (8): Expl. Mgr., Petrosil Resources Inc., Dallas, TX 1980-. Ind. Petrol. Geol. 1978-80. Maynard Oil Co., Ch. Geol. 1974-78. Lone Star Gas Co., Staff & Corporate Development. Texas Pacific Oil Co., Dist. Geol. Fifteen Oil Co., Dist. Geol. Warren Petrol. Corp., Dist. Geol. Mem. Am. Assn. Petrol. Geol., Am. Inst. Min., Met. & Petrol. Engr.

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AREA E

Charles R. Brammell, Chairman
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BRAMMELL, Charles R. (3): V. Pres. Development, Graham Energy, Metairie, LA 1981-; Consulting Devel. Geol. 1980-81. CNG Producing Co. (New Orleans, LA), Mgr. Development 1980; Chief Devel. Geol. 1977-80; Devel. Geol. 1973-77. Gulf Oil Corp., Expl. & Devel. Geol. 1960-73 and 1957-58. Sinclair Oil & Gas, Expl. & Devel. Geol. 1959-60. Hycalog, Mudlogging Engr. 1958-59. Mem. New Orleans Geol. Soc.

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McELROY, John H. (2): Sr. Coord., Expl. & Prod. Serv., Texaco Inc., Bellaire, TX 1977-; Expl. Coord. 1972-77; Midland Asst. Div. Mgr. 1969-72; Houston Div. Geol. 1967-69; Houston Asst. Div. Geol. 1961-67; Geol. 1958-61. Seaboard Oil Co., Geol., Asst. Dist. and Dist. Geol. 1951-58. Gulf Oil Corp., Surf. and Subsurf. Geol. 1948-51. Mem. Am. Assn. Petrol. Geol.

RASSINIER, E. A. (9): Independent, Houston, TX 1981-. Trunkline Gas Co., Dir. Resource Planning 1964-81; Ch. Petrol. Engr. 1953-64. Phillips Petrol. Co. (Prod. Dept.), Supv. Petrol. Engr. (Bartlesville, OK) 1951-52, Reg. Reservoir Engr. (Houston) 1947-50; Div. Reservoir Engr. (Oklahoma City) 1946; Petrol. Engr. (Bartlesville, Borger, Kansas City) 1942-43. Mem. Am. Assn. Petrol. Geol., Am. Inst. Min., Met. & Petrol. Engr., Soc. Petrol. Engrs., Houston Engr. & Scientific Soc., Houston Geol. Soc., Gas Res. Inst. Indus. Tech. Adv. Comm. (Unconventional Nat. Gas), Reg. Prof. Engr. (TX & MO). (Honorary Technical Advisor.)

RIEKER, James D. Jr. (2): V. Pres., Develop./Engineering, Texas Gas Exploration Corporation, Houston, TX 1981-; Mgr., Petrol. Engineering 1980-81; Reservoir Engr. & Sr. Reservoir Engr. 1976-80. Amoco Production Co. (Houston, TX), Oper. Engr. & Reservoir Engr. 1974-76; Prod. Engr. 1973-74. Mem. Am. Petrol. Inst., Soc. Petrol. Engrs. of Am. Inst. Min., Met. & Petrol. Engr., TX Mid-Continent Oil & Gas Assn.

**ROCHESTER, David A. (5): Asst. Mgr., Gas Supply, Public Service Elec. & Gas Co., Newark, NJ 1981-; Fuels Planning Engr. 1977-81; Nat. Gas Engr. 1971-77; Engr. 1967-71; Cadet Engr. 1966-67. River Gas Co., Engr. (Marietta, OH) 1964-66. Mem. Am. Gas Assn. (Task Force), Am. Inst. Min., Met. & Petrol. Engr., Assoc. Gas Dist. (Chmn. Operating Comm.), NJ Gas Assn. (Supply & Rates Comm.), Petrol. Expl. Soc. NY, Soc. Petrol. Engrs.

SEAL, Warren L. (2): V. Pres./Division Manager, Florida Exploration Co., New Orleans, LA 1978-. Exchange Oil & Gas Corp., Ch. Geol. 1972-78. Amoco Prod. Co., Ch. Geol. (New Orleans and Houston) 1967-72. Mem. Am. Assn. Petrol. Geol., New Orleans Geol. Soc.

AREA G

John C. Kucewicz, Jr., Chairman
Bill C. Burkman, Vice Chairman

BURKMAN, Bill C. (4): V. Pres., Exploration, States Petroleum Inc., Houston, TX 1982-. Consultant 1980-82. Santa Fe Energy, Reg. Mgr. 1969-79. Nat. Gas Pipeline Co., Dist. Geol. 1957-69. Geophysical Exploration, Party Chief 1951-57. Univ. Nebraska, Geol. 1951. Mem. Am. Assn. Petrol. Geol., Soc. Econ. Geol., Houston Geol. Soc.

HORSTMANN, Lane E. (3): Geol. Consultant & Ind. Prospect Generator, Houston, TX 1977-. Lone Star Prod. Co. (Enserch Expl.) (Midland, Abilene, San Antonio and Houston, TX), Expl. Mgr., Dist. Geol., and Geol. 1951-77. Mem. Am. Assn. Petrol. Geol., Houston Geol. Soc., Soc. Prof. Earth Scientists.

KUCEWICZ, John C. Jr. (1): Geol. Specialist (Dev. Geol.), CNG Producing Co., McAllen, TX 1981-; Geol. Specialist (New Orleans, LA) 1978-81. Texaco Inc. (New Orleans, LA), Geol. Asst. 1975-78. Mem. Am. Assn. Petrol. Geol., Corpus Christi Geol. Soc., New Orleans Geol. Soc. (past chmn.; Scouting Comm. 1978-81).

*MORRIS, Jeffery V. (5): Manager, Res. Geol., Transcontinental Gas Pipeline Corp., Houston, TX; Reg. Geol., Dist. Geol., Sr. Geol., Geol. 1961-. Sun Oil Co., Geol. (Houston) 1959-61. El Paso Nat. Gas Co., Geol. (New Orleans) 1956-59. Gulf Oil Corp., Geol. (New Orleans) 1954. Mem. Am. Assn. Petrol. Geol., Houston Geol. Soc. (Pres. 1978-79), Natural Gas Men of Houston.

SNIDER, Irving L. (1): V. Pres., Expl. & Prod., Total Petroleum, Inc., Houston, TX 1980-. Newmont Oil Co. (Houston, TX), V. Pres., Expl. 1969-80. Various independent and small companies 1964-69. Atlantic Refining Co., various positions, 1948-64. Mem. Am. Assn. Petrol. Geol., Houston Geol. Soc.

**SULLIVAN, Richard A. (7): Pres., So. County Gas and Bristol & Warren Gas Co., Hingham, MA 1959-. Boston Transit System, Exec. & Consulting Eng. 1949-58. Detroit Transit System, Gen. Manager 1945-48. City of Detroit, Public Util. Anal. 1942-45. U.S. Engr., Consulting Engr. 1941-42. MA Dept. Public Util., Elec. Engr. 1937-41. Mem. Am. Gas Assn., NE Gas Assn., Harvard Engr. Soc., MA Soc. Prof. Engr., NH Bar Assn.

AREA H

D. Keith Murray, Chairman
C. Keith Fisher, Vice Chairman

BARLOW, James A. Jr. (4): V. Pres., Barlow & Haun, Inc., Casper, WY 1957-. Forest Oil Corp., Geol. 1953-57. Ohio Oil Co., Geol. 1952-53. Mem. Am. Assn. Petrol. Geol., Assn. Prof. Geol. Scientists, Geol. Soc. Am., Rocky Mtn. Assn. Geol., WY Geol. Assn., Ind. Petrol. Assn. Mtn. States.

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DIEHL, Laurence A. (1): Expl. Mgr., Century Oil and Gas Corp., Englewood, CO 1981-. Cities Service Co. (Billings, MT, Casper, WY, Denver, CO), Expl. positions 1953-81. Mem. Rocky Mtn. Assn. Geol., KS Geol. Soc., WY Geol. Soc.

FISHER, C. Keith (3): Consulting Geol., Denver, CO 1931-. Panhandle Eastern Pipe Line Co. (Denver, CO), Reg. Geol. 1977-81. U.S. Geological Survey (Denver), Geol. 1974-77. Ind. Geol. (Denver) 1973-74. American Stratigraphic Co., Gen. Mgr., Vice Pres. (Denver) 1961-73; Manager (Billings & Casper) 1955-61. Canadian Stratigraphic Serv., Ltd., Geol. (Calgary) 1952-55. Panhandle Eastern Pipe Line, Geol. (Liberal, KS) 1949-52. Mem. Am. Assn. Petrol. Geol., Am. Inst. Prof. Geol., Rocky Mtn. Assn. Geol., WY Geol. Assn., MT Geol. Soc.

GERHARD, Lee C. (1): Prof. Geol., Colorado School of Mines, Golden, CO and Assoc. Dir., Potential Gas Agency and Consultant, Gerhard and Associates 1982-. Supron Energy Corp. (Englewood, CO), Expl. Mgr. 1981-82. ND Geol. Survey, State Geol. & Dir. 1977-81; Asst. State Geol. 1975-77. Univ. ND, Chmn. and Prof. Geol. 1977-81; Assoc. Prof. Geol. 1975-77. West Indies Lab. and Fairleigh Dickinson Univ., Act. Dir. and Assoc. Prof. Geol. 1975; Asst. Dir. and Assoc. Prof. 1972-75. Univ. So. CO, Assoc. Prof. Geol. 1966-72. Sinclair Oil and Gas Co., Reg. Stratigrapher 1965-66; Expl. Geol. 1964-65. Amerada Petrol. Corp., Party Chief 1962. Univ. KS, Inst. Geol., Asst. Inst. Geol., Teaching Fellow 1960-64. Mem. Am. Assn. Petrol. Geol., Am. Inst. Prof. Geol., Assn. Am. State Geol., CO Scient. Soc., Geol. Soc. Am., ND Geol. Soc., Rocky Mtn. Assn. Geol., Soc. Econ. Paleon. & Min.

HABBIT, Robert D. (5): Mgr. Reservoir Engineering, El Paso Natural Gas Co., El Paso, TX 1978-; Mgr. Reservoir Studies 1978; Cons. Reservoir Geol. 1977-78; Staff Geol. 1966-77. Ind. Geol. (Houston) 1965-66. El Paso Natural Gas Co., Sr. Reservoir Geol. (Houston) 1957-65. Sohio Petroleum Co., Geophysicist/Geol. (Gulf Coast-Rky. Mtns.) 1954-57. Mem. Am. Assn. Petrol. Geol. (CPG #166), Am. Inst. Prof. Geol. (Cert. #2489), Am. Inst. Min., Met. & Petrol. Engr., Soc. Expl. Geophysicist, Rocky Mtn. Assn. Geol., El Paso Geol. Soc.

HAWK, David H. (4): Sr. V. Pres., Horn Resources Corp., Boise, ID 1981-. Sundance Oil Co. (Denver, CO), V. Pres. Expl. 1980-81. IGC Production Co., V. Pres. & Gen. Mgr. and Intermountain Gas Co. (Boise, ID), Mgr. Expl. & Prod. 1977-80; Nat. Res. Advisor 1973-76. Tenneco Oil Co., Expl. Geol. (Denver) 1972-73. Atlantic Richfield, Expl. Geol. (Dallas, TX & Lafayette, LA) 1970-72. Mem. Am. Assn. Petrol. Geol. (Energy Minerals Div.), ID Assn. Prof. Geol., Geol. Soc. Am., Rocky Mtn. Assn. Geol., Geothermal Resource Council, Am. Gas Assn.

KIDWAI, Moid (4): Staff Res. Engr., Northern Natural Gas Co., Denver, CO 1981-; Sr. Res. Engr. (Denver, CO and Omaha, NB) 1978-80; Res. Engr. 1975-77. Metro Subway, Geol. (Washington, DC) 1974-75. Oil & Gas Development Corp., Petrol. Engr. (Pakistan) 1968-72. Mem. Am. Assn. Petrol. Geol., Soc. Petrol. Engr.

McPEEK, L. A. (2): Consulting Geol., Denver, CO 1972-. Koch Exploration, Expl. Mgr. Rocky Mtn. Div. (Denver, CO) 1969-72. Pan American Petroleum (Amoco), Dist. Oper. Geol. (Denver, CO and New Orleans, LA) 1962-69. Mem. Am. Assn. Petrol. Geol., Rocky Mtn. Assn. Geol., WY Geol. Assn.

MOTSCH, A. Sherrill (2): Dist. Devel. Geol., Marathon Oil Co. (formerly The Ohio Oil Co.), Casper, WY 1979-; Devel. Geol. 1967-79; on staff of Div. Geol. & Div. Expl. Mgr. 1957-66; Field & Devel. Geol. (Cody, WY) 1953-57; Field Geol. (Rawlins, WY) 1951-53. Mem. WY Geol. Assn.

MURRAY, D. Keith (8): Mgr. Spec. Proj., Energetics, Inc., Englewood, CO 1981-. Colorado Sch. Mines Research Inst. (Golden, CO) 1979-81. CO Geol. Surv. (Denver, CO) 1973-79. Coronado Oil Co., Cons. Geol. (Denver) 1969-73. Sinclair Oil Corp. (Denver) 1966-69. Cons. Geol. (Denver) 1962-66. Clark Oil & Refining Corp. (Denver) 1960-62. Ind. Geol. (Los Angeles) 1959-60. Manabi Expl. Co. (Ecuador, SA) 1956-58. Shell Oil Co. (CA, UT, NV, LA) 1953-56. Mem. Am. Assn. Petrol. Geol. (Rocky Mtn. Sec. Councillor, Energy Min. Div., Mem. House of Delegates, Natl. AAPG V. Pres. 1979-80), Am. Inst. Prof. Geol., CO Sci. Soc., Denver Coal Club, Geol. Soc. Am., Rocky Mtn. Coal Min. Inst., Rocky Mtn. Petrol. Pioneers, WY Geol. Assn.

POWERS, Richard B. (3): Geol., U.S. Geological Survey, Br. Oil & Gas, Lakewood, CO 1974-. Consultant (Denver) 1971-74. Bolyard & Assoc., V. Pres. (Denver) 1968-71. Tenneco Oil, Sr. Staff Geol. (Houston) 1967-68; Dist. Geol. (Casper) 1965-67; Dist. Mgr. (Pittsburgh) 1962-65; Reg. Geol. (Casper & Denver) 1959-62. Petrobras, Geol. (Belem, Brazil) 1958-59. Pure (Union) Oil Co., Geol. (Grand Junction, CO) 1952-58. Mem. Am. Assn. Petrol. Geol. (Membership Committee), Rocky Mtn. Assn. Geol., WY Geol. Assn., Canadian Soc. Petrol. Geol.

SANBORN, Albert F. (3): Expl. Mgr., Frontier Div., Buckhorn Petroleum Co., Denver, CO 1981-. Cons. Geol. (Denver, CO) 1978-80. Chevron U.S.A., Sr. Geol. (Denver) 1963-78; Div. Stratigrapher (Salt Lake City) 1959-63; Dist. Stratigrapher 1955-59; Geol.-Stratigrapher 1954-55; Geol.-Stratigrapher (Los Angeles) 1952-54. Mem. Am. Assn. Petrol. Geol., Assn. Ind. Petrol. Geol., Rocky Mtn. Assn. Geol.

***STRACKE, Kenneth J.** (4): Director, Northwest Pipeline Corp., Salt Lake City, UT 1975-. Consultant (Salinas, CA) 1974-75. Union Oil Co. of CA, Dist. Mgr. (Santa Rosa, CA) 1972-74; Dist. Oper. Mgr. (Orcutt, CA) 1969-72; Dist. Prod. Supt. 1968-69; Dist. Engr. 1968; Engr. Supv. (Coalinga, CA) 1962-68; Petrol. Engr. (San Joaquin Valley, CA) 1954-62. Mem. Am. Gas Assn. (Expl. & Prod. Comm.), Reg. Prof. Engr. UT, Soc. Petrol. Engr. of Am. Inst. Min., Met. & Petrol. Engr. (Chmn. San Joaquin Valley, CA Sec. 1962).

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WOODBURY, H. O. (1): Div. Geol. Rocky Mtn. Div., Chevron U.S.A. Inc., Denver, CO 1981-. Standard Oil Co. of California, Indonesia 1979-81; New Orleans, LA 1972-81; Tripoli, Libya 1971-72; New Orleans, LA 1965-71; Chevron Research Corp., La Habra, CA 1964; New Orleans, LA 1955-64; Casper, WY and Denver, CO 1946-55. Mem. Am. Assn. Petrol. Geol. (Cert.), Rocky Mtn. Assn. Geol.

AREA I

Robert D. Habbit, Chairman
Edward M. Allshouse, Vice Chairman

ALLSHOUSE, Edward M. (3): Sr. Reservoir Geol., El Paso Natural Gas Co., El Paso, TX 1973-. Mem. Am. Assn. Petrol. Geol. (SW Sect. Delegate), Am. Inst. Min., Met. & Petrol. Engr. (V. Chmn. El Paso Chapter), El Paso Geol. Soc. (Sec.-Treas.).

DAVIES, David J. (3): Geol., Expl. and Dev., Southern Union Exploration Co. (SX), Dallas, TX 1977-82. Enserch Exploration, Inc. (Lone Star Producing Co.), Geol. (Dallas) 1975-77. Mem. Am. Assn. Petrol. Geol., Soc. Econ. Paleon. and Min., Dallas Geol. Soc.

**GASS, Bernie (3): Mgr., Fuel Supply, AZ Pub. Serv. Co., Phoenix, AZ 1973-82; Mgr. System Gas Constr. 1972; Consultant, New Bus. Develop. 1969-71; Engr., Power Prod. 1966-68; Engr., Gas Engineering 1961-65. Mem. Am. Soc. Mech. Engrs., Pacific Coast Gas Assn.

HABBIT, Robert D. (5): Mgr. Reservoir Engineering, El Paso Natural Gas Co., El Paso, TX 1978-; Mgr. Reservoir Studies 1978; Cons. Reservoir Geol. 1977-78; Staff Geol. 1966-77. Ind. Geol. (Houston) 1965-66. El Paso Natural Gas Co., Sr. Reservoir Geol. (Houston) 1957-65. Sohio Petroleum Co., Geophysicist/Geol. (Gulf Coast-Rky. Mtns.) 1954-57. Mem. Am. Assn. Petrol. Geol. (CPG #166), Am. Inst. Prof. Geol. (Cert. #2489), Am. Inst. Min., Met. & Petrol. Engr., Soc. Expl. Geophysicists, Rocky Mtn. Assn. Geol., El Paso Geol. Soc.

KOTTLOWSKI, Frank E. (3): Dir. & Sr. Geol., NM Bureau of Mines & Mineral Resources, Socorro, NM 1974-; Assoc. Dir., Sr. Geol., Econ. Geol. 1951-74. Indiana Geol. Surv., Party Chief, Coal Div. 1947-51. Indiana Univ. Geol. Dept., Inst. 1950-51. Mem. Am. Assn. Petrol. Geol. (Editor 1971-75), Geol. Soc. Am. (Fellow), Soc. Econ. Geol., Assn. Am. State Geol., Soc. Econ. Paleon. & Min., Assn. Prof. Geol. Scientists (Past Pres. NM section), Am. Assn. Adv. Science (Fellow).

MARTIN, Gregory W. (1): Sr. Geol., Wexpro Co., Farmington, NM 1981-; Geol. 1980-81; Assoc. Geol. 1979-80. Texaco Inc. (Houston, TX), Adv. Geol. and Proj. Geol. 1979; Dev. Geol. 1977-79; Expl. Geol. 1976-77; Geophys. Processor 1975-76. Mem. Am. Assn. Petrol. Geol., Four Corners Geol. Soc.

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AREA J-N

Alan F. Chatfield, Chairman
Joe E. McGarrah, Vice Chairman

CHATFIELD, Alan F. (4): Expl. Mgr., Berry Petroleum Corp., Oklahoma City, OK 1982-. Chatfield Petroleum Corp., Pres. (Oklahoma) 1981-82; Berry Petroleum Corp., Chief Geol. 1980-81. L. R. French, Jr., Expl. Mgr. 1980. GHK Corp., Expl. Mgr. 1976-80. Carlsberg Petroleum Corp., Sr. Staff Explor. (International & CA) 1974-76. Oceanic Exploration Co., Geophys. and Local Overseas Mgr. (International and CO) 1973-74. Conoco, Geophys. (International and OK) 1972-73. GHK Corp., Geophys. (TX and OK) 1971. Humble Oil & Refining Co., Geophys. (TX and OK) 1967-71. Mem. Am. Assn. Petrol. Geol., Soc. Expl. Geophy., OKC Geol. Soc., Geophy. Soc. OKC.

*KNOBLOCH, Mike H. (1): Mgr. Prosp. Eval., Panhandle Eastern Pipe Line Co., Kansas City, MO 1981-; Asst. Chief Res. Engr. 1976-81; Res. Engr. (Liberal, KS) 1971-76. Mobil Oil Corp., Field Engr. (Countyline, OK) 1969. Mem. Am. Gas Assn. (Reserves Subcommittee), Soc. Petrol. Engrs.

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AREA J-S

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C. K. McLaughlin, Vice Chairman

GAINES, Robert B. (2): Res. Engr., Nortex Oil & Gas Co., Midland, TX 1981-; Northern Natural Gas Co. (Nortex), Expl. Geol. 1970-81; Res. Engr. (Omaha, NB) 1956-70. So. California Petroleum, Expl. Geol. (Midland, TX) 1955-56. Ohio Oil Co. (Marathon), Expl. Geol. (Midland, TX) 1951-55. Mem. Am. Assn. Petrol. Geol., Am. Inst. Min., Met. & Petrol. Engr., Am. Inst. Prof. Geol., Soc. Econ. Paleon. & Min., West TX Geol. Soc., Reg. Prof. Engr. TX.

MARCZYNSKI, Louis F. (1): Exploitation Engr. Spec. Superior Oil Co., Midland, TX 1982-. Northern Natural Gas Co. (Internorth), Reg. Mgr. Res. Eval. (Midland, TX) 1978-82; sixteen years experience in various engineering positions 1966-82. Mem. Am. Gas Assn., Nat. Gas Soc. of Permian Basin, Soc. Petrol Engr. (AIME).

*McLAUGHLIN, C. K. (1): Reg. Mgr. Sup. Eval. & Reserve Mgmt. Permian Basin, Northern Natural Gas Co., Midland, TX 1980-. ANR Production Co., Staff Res. Engr. (Houston, TX) 1978-80. Forest Oil Co., Div. Res. Engr. (Midland, TX) 1960-78. H. S. Cole, Resident Mgr. (Santa Domingo, Dom. Rep.) 1958-60. Amoco, Dist. Res. Engr. (Denver, CO) 1951-58. Mem. Nat. Gas Soc., Soc. Petrol. Engr., TX Prof. Engr.

**PERKINS, Kenneth R. (1): Sr. Gas Contracts Rep., Westmar Trans. Co., Amarillo, TX.

AREA K

Alexander Sisson, Chairman

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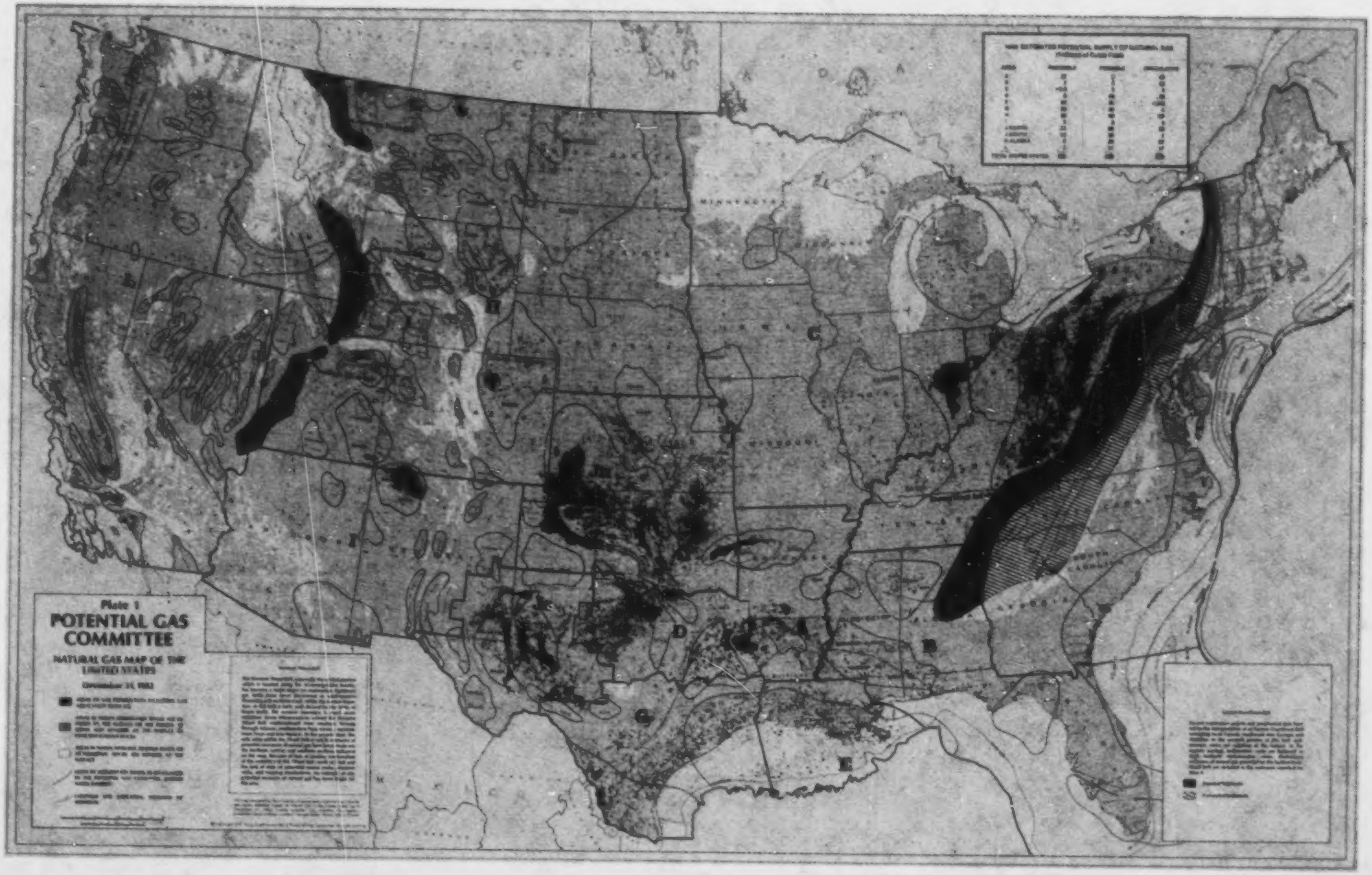
Plate 1
POTENTIAL GAS COMMITTEE
NATURAL GAS MAP OF THE UNITED STATES
December 31, 1982
C A N A D A
M E X I C O
D
E
G
B
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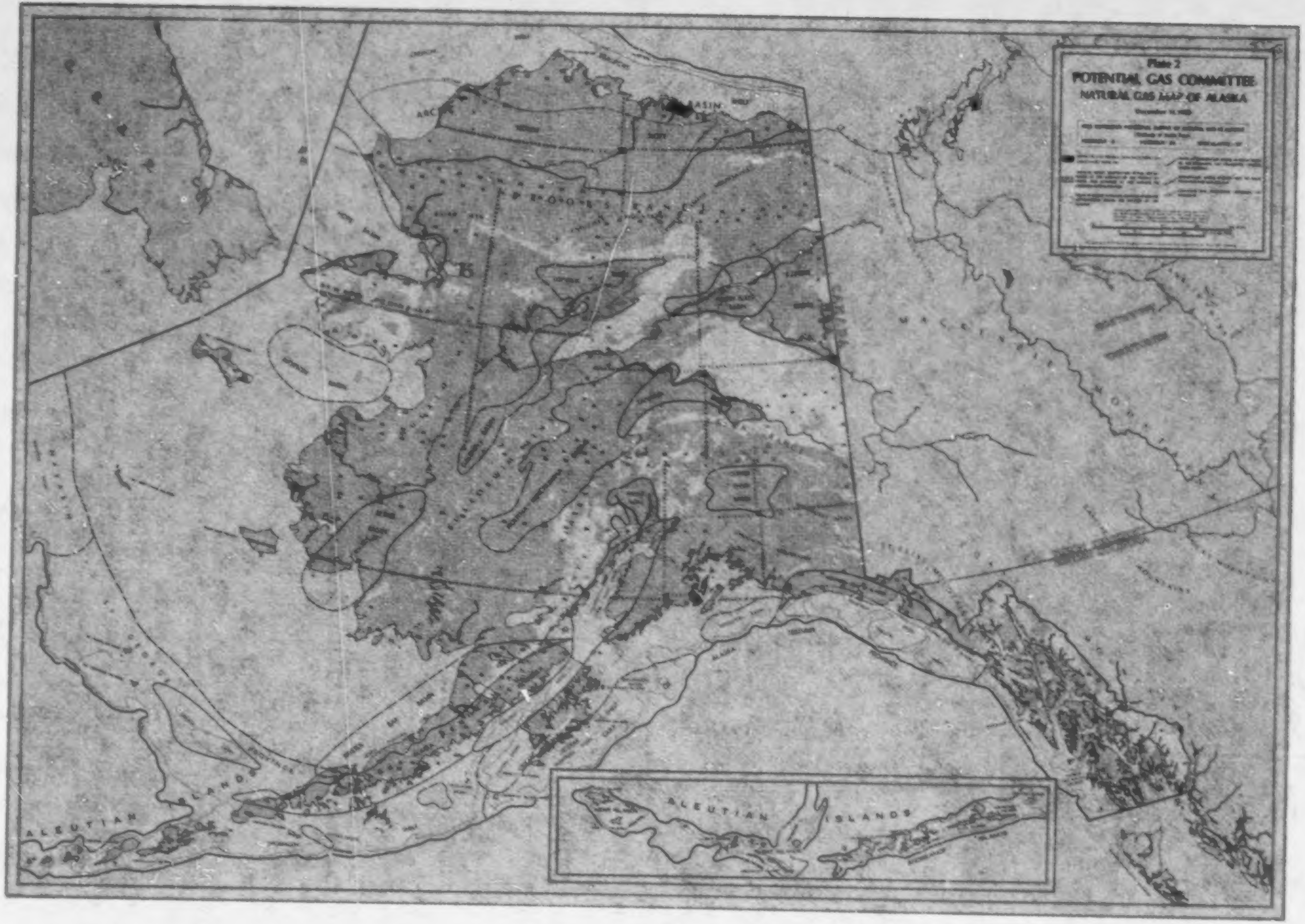


Plate 2
POTENTIAL GAS COMMITTEE
NATURAL GAS MAP OF ALASKA
ARCTIC
BASIN
ALEUTIAN ISLANDS
ALEUTIAN
ISLANDS

Senator MURKOWSKI. Thank you very much, Dr. Kent.

In your summary, I noted the summary in your prepared statement which has gone into the record, but you brought it out in six or seven points, I believe, is that contained in here as well?

Dr. KENT. No, sir; it is not, but I would be glad to supply a copy of the written statement as well.

Senator MURKOWSKI. Your summary is a little more extensive than your conclusions in your prepared statement.

Dr. KENT. I certainly will.

Senator MURKOWSKI. Thank you.

Our next witness is Mr. Steve Plotkin—is that correct, Mr. Plotkin?

Mr. PLOTKIN. Yes.

Senator MURKOWSKI. Office of Technology Assessment, Congress of the United States.

We welcome you to the committee. We look forward to your testimony. You may proceed.

STATEMENT OF STEVEN E. PLOTKIN, PROJECT DIRECTOR, U.S. NATURAL GAS AVAILABILITY STUDY, OFFICE OF TECHNOLOGY ASSESSMENT, CONGRESS OF THE UNITED STATES

Mr. PLOTKIN. Thank you, Mr. Chairman.

I appreciate your invitation to testify on OTA's assessment of natural gas resources in the U.S. lower 48 States.

I will restrict my spoken testimony to the subject of conventional gas resources, because of the time limitations.

My written testimony does briefly review the unconventional resources, and I will be glad to address these in the question and answer period.

Senator MURKOWSKI. Your testimony will be entered into the record.

Mr. PLOTKIN. Thank you, sir.

A primary result of our assessment of natural gas resources was that we could find no convincing basis for the common argument that the lower 48 States are so intensively explored and their geology so well known that there can be a substantial consensus on the magnitude of their gas resource base. We concluded that the remaining conventional natural gas in the lower 48 States may be as low as 430 Tcf, or as high as 900 Tcf.

This range of resource base estimates implies, at the low end, an impending precipitous decline in production from current levels; and, at the high end, a possible continuation of present production rates, or even higher, through at least the next two or three decades.

There are five primary issues about the resource base estimates over which there are a considerable amount of disagreement and a ready availability of strong and opposing arguments.

These five issues are: First, the implications of past discovery trends; second, the resource potential of small fields; third, the potential of obtaining additional reserves from our older fields; fourth, the potential of frontier areas, including the deep fields; and fifth, the potential of stratigraphic traps. Let me briefly discuss each.

Extrapolation of past discovery trends has generally led to extremely pessimistic estimates of the magnitude of the gas resource base. Exclusive reliance on discovery trend extrapolation for resource base assessment, therefore, can yield conclusions about the magnitude of the resource base that are radically different from those that result from using other assessment methods.

Resource optimists argue that the disappointing trends in gas discovery of the past few decades have resulted from controlled gas prices, high levels of proved reserves, and limited markets that until recently gave little incentive for high-risk or high-cost drilling. They argue that extrapolation of these trends is invalid because the economic and regulatory conditions that created the trends have changed. Resource pessimists, on the other hand, argue that the trends are driven mainly by a depleting resource base, and are affected only minimally by economic and regulatory conditions; therefore, extrapolation is valid.

OTA does not believe that past discovery trends were unaffected by economic and regulatory conditions, but we also believe these trends do strongly reflect the character of the resource base and can be used as an important input to resource estimation. Placed in their proper perspective, pessimistic past discovery trends place a substantive demand on optimistic resource estimators to justify the magnitude of their estimates on some basis other than the irrelevance of the past trends.

The second issue is the potential of small fields. Although small fields that contain less than 60 billion cubic feet of gas have in the past played a minor role in gas production, some analysts believe that small fields will have a major role in the future because of increased prices. The difference between optimistic and pessimistic estimates of the potential contribution of small fields to future production may be 100 Tcf or more. In OTA's judgment, the arguments on both sides are based primarily on unproven statistical models and on economic tradeoffs that are highly sensitive to gas prices. Only time and further exploration and development will settle this issue.

The third issue, the possibility of additional reserves from the Nation's older fields, is a particularly controversial source of uncertainty. Much of the gas in these fields is forever price-controlled under current law. There are sharp disagreements about the extent to which the amount of gas that can be recovered from older producing fields may grow in response to price increases. OTA concludes that the potential additional reserves that may be obtained from older fields is about 43 to 65 Tcf. These reserves will be obtained only if adequate financial incentives are provided to overcome the effect of low-controlled prices. While the current law provides enough incentive to produce at least 20 to 35 Tcf of this gas, capturing the remainder may require additional incentives.

The fourth issue is the potential of frontier areas, including deep gas. Although all resource analysts consider areas such as the deep water Gulf of Mexico, the deep Anadarko basin, and the western overthrust belt to have considerable gas potential, sharp disagreements exist over the actual amount of recoverable resources in these areas. Estimates of the recoverable resource potential in these areas vary by up to 100 Tcf or more; for example, the USGS and the Potential Gas Committee differ by nearly 30 Tcf in their assessments of the eastern Gulf of Mexico alone. In OTA's opinion, most of this variation can be eliminated only by further exploration and development.

The final issue is the potential of stratigraphic traps. Stratigraphic traps are barriers to petroleum migration formed by gradual changes in the permeability of sedimentary layers rather than by abrupt structural shifts and deformation of layers. The argument for a high resource potential in these traps is that, because the structural traps are easier to locate, they have in the past been the primary target for exploration, and the stratigraphic potential has not been tested to the same extent. The counterargument is that these traps have not been neglected, that past exploration efforts, some quite successful, have been aimed precisely at this type of trap. In OTA's opinion, although some giant stratigraphic traps may remain undiscovered, their number is unlikely to be large.

To summarize: Upon examining a variety of natural gas resource base estimates and the arguments for and against different views of the U.S. gas resource potential, OTA concludes that the remaining resource uncertainties are too large to justify either an optimistic or a pessimistic view at this time. For example, we believe that an appropriate range for the conventional resource base is about 430 to 900 Tcf. The low end of this range implies a rapid drop in conventional gas production within a decade; whereas, the high end, in its most optimistic interpretation, would allow production to continue at today's level for at least the remainder of the century.

The high level of uncertainty regarding the natural gas resource base has important implications for public policy concerning the development of gas supplies and their utilization, as well as the supply utilization of competing energy sources. In particular, the resource uncertainty implies that a high value should be placed on policies that promote a flexible energy system that can respond rapidly and efficiently to emerging trends in gas supply, either up or down. Such policies might include bolstering the collection and interpretation of data on gas discovery and development, promoting research and development on unconventional gas sources and more efficient gas utilization, and providing market incentives to energy utilization technologies with multifuel capabilities.

This concludes my testimony.

[The prepared statement of Mr. Plotkin follows:]

TESTIMONY OF STEVEN E. PLOTKIN
PROJECT DIRECTOR
U.S. NATURAL GAS AVAILABILITY STUDY
OFFICE OF TECHNOLOGY ASSESSMENT
BEFORE THE SUBCOMMITTEE ON ENERGY REGULATION
COMMITTEE ON ENERGY AND NATURAL RESOURCES

APRIL 26, 1984

Thank you for your invitation to testify on OTA's assessment of natural gas resources in the U.S. Lower 48 States. This assessment is part of a study of the availability of natural gas in the U.S., requested by the House Committee on Energy and Commerce and endorsed by Senator Domenici of the Senate Committee on Energy and Natural Resources.

I will begin my testimony with our conclusions about the size and nature of conventional gas resources. I will then explain how we arrived at these conclusions and discuss their context and implications. Next, I will present OTA's preliminary conclusions about three "unconventional" gas resources: gas from Devonian Shales, tight sands, and coal seams. Work on these resources is continuing, and our conclusions have not been completely reviewed. Finally, I will briefly touch on three additional potential sources of natural gas that are relevant to the Subcommittee's interests but which OTA has not investigated in detail: "deep earth gas", gas from geopressurized aquifers, and gas hydrates.

CONVENTIONAL GAS RESOURCES

When we began our assessment of future gas availability, we found a substantial consensus about future gas production. Of 14 forecasts that projected a year 2000 gas production level, 13 fell within the range of 11 to 15 trillion cubic feet (TCF)/yr. To place this in perspective, it's important to keep in mind that only a comparatively modest part of any gas production in the year 2000 -- probably no more than 3 or 4 TCF/yr -- could be derived from reserves that were at the time of the forecasts already in the Nation's inventory of proved reserves. The rest of year 2000 production would have to come from gas which, at the time of the forecasts, had not yet been identified by drilling.

This seemingly high level of agreement about the Nation's ability to produce gas 18 years in the future, gas which had not even been discovered yet, was surprising to us. We think that an important factor behind the consistency amongst the forecasters is that most of them chose to use similar estimates of gas resources -- like those of the U.S. Geological Survey and Potential Gas Committee -- in their models. It was immediately apparent to us that we could not evaluate the validity of these supply forecasts without carefully examining the basis for this apparent consensus on gas resources. Consequently, we spent a considerable amount of time examining the nature of this consensus.

A primary result of our examination was that we could find no convincing basis for the common argument that the area of the Lower 48 States is so intensively explored and its geology is so well known that there can be a substantial consensus on the magnitude of its gas resource base. We concluded that a reasonable range for the amount of the remaining conventional natural gas in the U.S. Lower 48 that is recoverable under present and easily foreseeable technological and economic conditions is very wide, on the order of 430 to 900 TCF. (This compares with total, cumulative production to date of about 650 TCF.) This implies that it is not possible to determine whether or not the resource base will act as a severe brake on gas production in this century. If the lower end of the range is correct, domestic gas production by conventional means MUST decline precipitously by the 1990's; by the year 2000, production may be as low as 9 TCF/yr, or half of the early 1980's production rate. At the upper end of the range, the current production level might be maintained through this century, although this will require both a vigorous exploration and development program and resource base characteristics that promote rapid exploitation.

Method of Analysis

We arrived at the above conclusions by the following process:

We first collected, examined, and compared existing estimates of the U.S. resource base. These are available from a variety of sources, ranging from industry organizations such as the Potential Gas Committee to government agencies, e.g. the U.S. Geological Survey, to individuals such as Richard Nehring of RAND and H. King Hubbert. Table 1 displays some of these estimates.

Next, we examined the basic methodologies by which the estimates were made, searching especially for potential problems with these methodologies.

Third, we examined the physical implications of the estimates and asked whether these are plausible. More precisely, we first asked whether a substantial break with past and recent discovery trends and patterns is necessary if the estimates are to be met. If so, we then asked whether a credible explanation was available to explain such a break. For example, we

Table 1 —Alternative Estimates of Ultimately Recoverable and Remaining Natural Gas in the United States (TCF)

Estimator	Publication date	Ultimately recoverable resources: Lower 48	Ultimately recoverable resources: Total U.S.	Remaining resources Lower 48, 1983[a]	Remaining resources not yet added to proved reserves, Lower 48, 1983[b]
Mobil	1974	—	1,076-1,241-1,456	—	—
Garrett	1975	—	1,313	—	—
Wiorkowsky	1975	1,221-1,289-1,357[a]	—	595-663-731	421-489-557
Bromberg/Hartigan	1975	966[c]	—	340	166
Exxon Attainable	1976	—	917-1,112-1,577	—	—
Shell	1977	946	910-1,075-1,260	320	146
IGT	1980	—	1,288-1,798	—	—
PGC	1983	1,542	1,711	916	742
Hubbert (1)	1980	870	—	244	70
Hubbert (2)	1980	989[d]	—	363	189
RAND	1981	902	989	283	109
USGS	1981	1,400	1,422-1,541-1,686	774	600

[a] Approximate cumulative Lower 48 production through 1982 was 631 TCF, of which about 5 TCF is in underground storage. "Remaining resource" is "Lower 48" (ultimately recoverable) column value minus 631 TCF plus 5 TCF.

[b] Lower 48 proved reserves assumed to be 169 TCF at 12/31/82 (excluding underground storage).

[c] Original estimate for onshore gas only. Total arrived at by adding USGS (mean) estimate for ultimately recoverable offshore gas in Lower 48 (235 TCF).

[d] Based on an analysis of finding rates by David Root, USGS.

SOURCE. **Mobil**—J. D. Moody and R. E. Geiger, "Petroleum Resources: How Much Oil and Where," *Technology Review*, March/April 1975. Verbal comments by John Moody at a FPC presentation, Apr. 14, 1975.

Garrett—R. W. Garrett, "Average of Some Estimates by Major Oil Companies and Others, 1975," oral presentation at Executive Conference of the American Gas Association, June 9-11, 1975, cited in Potential Gas Committee, *A Comparison of Estimates of Ultimately Recoverable Quantities of Natural Gas in the United States*, Gas Resource Studies No. 1, Potential Gas Agency, April 1977.

Wiorkowski—J. J. Wiorkowski, *Estimation of Oil and Natural Gas Reserves Using Historical Data Series: A Critical Review*, unpublished manuscript, 1975, cited in J. J. Wiorkowski, "Estimating Volumes of Remaining Fossil Fuel Resources: A Critical Review," in *J. Am. Stat. Assoc.*, vol. 76, No. 875, September 1981.

Bromberg/Hartigan—L. Bromberg and J. A. Hartigan, *Report to the Federal Energy Administration*, unpublished manuscript, 1975, cited in Wiorkowski (1981), noted above.

Exxon—Exxon Co., U.S.A., Exploration Department, "U.S. Oil and Gas Potential," March 1976. *Oil and Gas Journal*, "Exxon Says U.S. Still Has Vast Potential," Mar. 22, 1976.

Shell—C. L. Blackburn, Shell Oil Co., "Long-Range Potential of Domestic Oil and Gas," presented at NAPIA/PIRA Fall Conference, Boca Raton, Fla., Oct. 19, 1978. *Oil and Gas Journal*, "Shell: Alaska Holds 58% of Future U.S. Oil Finds," Nov. 20, 1978.

IGT—J. D. Parent *A Survey of United States and Total World Production, Proved Reserves, and Remaining Recoverable Resources of Fossil Fuels and Uranium*, Institute of Gas Technology, Chicago, August 1980, cited in American Gas Association, "Energy Analysis: A Comparison of U.S. and World Remaining Gas and Oil Resources," Aug. 7, 1981.

PGC—Potential Gas Agency, *News Release—February 28, 1983.*

Hubbert (1) (2)—M. K. Hubbert, "Techniques of Prediction as Applied to the Production of Oil and Gas," in *Oil and Gas Supply Modeling*, S. I. Gass (ed.), National Bureau of Standards Special Publication 631, May 1982.

RAND—R. Nehring with E. R. Van Driest II, *The Discovery of Significant Oil and Gas Fields in the United States*, R-2654/1-USGS/DOE, RAND Corp., January 1981.

USGS—G. L. Dolton, et al., *Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States*, U.S. Geological Survey Circular 860, 1981.

calculated the number of large fields that would have to be found in order for the estimated resource base to become part of the Nation's proved reserves, and compared this to the discovery history of such fields. Also, we examined potential sources of additional gas that might not be reflected in past trends and thus that might explain resource estimates that seemed of higher magnitude than could be readily explained by the discovery history. These sources included so-called "deep" gas, i.e., gas below 15,000 feet, gas in subtle stratigraphic traps, gas in small, previously sub-economic fields, and so on.

Fourth, we examined the basic question of whether or not economic and political forces had so distorted the discovery history that it was of little value in projecting future resources.

Resource Uncertainties

In pursuing our analyses, we found ourselves growing more and more impressed with the amount of disagreement and the ready availability of strong and opposing arguments about virtually every one of the basic resource magnitude issues we examined. While the two most prominent resource estimates, those of the Geological Survey and the Potential Gas Committee, are in close agreement, there is a lack of consensus about the basic underlying issues (see below). This convinces us that it would be unwise to place undue faith in this agreement. I will now briefly survey some of the substantive issues concerning resource base estimates that we examined.

1. The Use of Past Discovery Trends

The extrapolation of past trends in the discovery of natural gas has generally led to pessimistic estimates of the magnitude of the gas resource base. For example, of the resource base assessments examined by OTA, three of the four that used trend extrapolation techniques arrived at estimates that were at least 400 TCF below the USGS median estimate of 774 TCF remaining to be produced (as of 1983). Exclusive reliance on discovery trend extrapolation for resource base assessment, therefore, can yield conclusions about the magnitude of the resource base that are radically different from those that result from using other assessment methods.

The validity of using past discovery trends to estimate the magnitude of the resource base depends on whether the trends are affected more by the physical nature of the resource base than by the general economic and regulatory climate of the times. Resource "optimists" argue that the disappointing trends in gas discovery of the past few decades have resulted from controlled gas prices, high levels of proved reserves, and limited markets that until recently gave little incentive for high-risk or high-cost drilling. They argue that extrapolation of these trends is invalid because the economic and regulatory conditions that created the trends have changed. Resource "pessimists" argue that the trends are driven mainly by a depleting resource base and are affected only minimally by economic and regulatory conditions; therefore, extrapolation is valid.

In addition to this basic issue, other questions have arisen over the validity and interpretation of resource estimates based on extrapolation of past trends. For example, the accuracy of early records of gas discovery and production is questionable; thus, trend analyses cannot accurately incorporate the entire discovery and production history. Also, the precise economic, technological, geographic, and geologic boundaries of these estimates are difficult to define.

OTA believes that past discovery trends were affected more than "minimally" by economic and regulatory conditions, but we also believe that these trends do strongly reflect the character of the resource base and can be used as an important input to resource estimation. Placed in their proper perspective, "pessimistic" past discovery trends place a substantive demand on "optimistic" resource estimators to justify the magnitude of their estimates on some basis other than the irrelevance of past trends.

2. The Potential of Small Fields

Although small fields that contain less than 60 billion cubic feet (BCF) of gas have in the past played a minor role in gas production, some analysts believe that small fields will have a major role in the future. The main argument here is that in the past small fields went unreported and unproduced because gas prices were too low to cover well completion and operating costs, whereas higher gas prices will now allow such fields to be produced. The difference between optimistic and pessimistic estimates of the potential contribution of small fields to future production may be 100 TCF or more. In OTA's judgment, the arguments on both sides are based primarily on unproven statistical models of field size distributions and on economic tradeoffs that are highly sensitive to gas prices. Only time and further exploration and development will settle this issue.

3. New Gas From Old Fields

There are sharp disagreements about the extent to which the amount of gas that can be recovered from older producing fields may grow in response to price increases. The mechanisms to increase the "ultimately recoverable resources" of these fields might include lower abandonment pressures, drilling at smaller spacing to locate gas pockets that otherwise would not be drained, and fracturing the reservoir rock to allow recovery from low-permeability portions of fields. Currently, estimates of the potential increase in recoverable resources range from a few TCF to about 50 TCF.

OTA has examined this issue in some detail. We conclude that the potential additional reserves that may be obtained from older fields, over and above the completion of their normal development history, is about 43-65 TCF. These reserves will be obtained only if adequate financial incentives are provided to overcome the effect of low controlled prices. The current Natural Gas Policy Act and accompanying Federal Energy Regulatory Commission (FERC) regulations do provide some of this incentive; OTA estimates that at least 20-35 TCF of the potential will be captured with no further regulatory changes. The remaining 19-38 TCF can be captured by price decontrol or other incentives, although a part of this may be captured by portions of the present legislation whose effects OTA was unable to gauge.

Our analysis is explained in detail in a Staff Memorandum on the Effects of Decontrol on Old Gas Recovery, issued this February.

4. The Potential of Frontier Areas, Including Deep Gas

Although all resource analysts consider areas such as the deep-water Gulf of Mexico, the deep Anadarko Basin, and the Western Overthrust Belt to have considerable gas potential, sharp disagreements exist over the actual amount of recoverable resources in these areas. Recent indications of engineering problems and rapid pressure declines from deep wells in the Anadarko, coupled with price declines from previous very high levels, raise doubts about whether much of this area's gas resource will be part of the (currently) economically recoverable resource. Some of these doubts must be tempered, however, by recent declines in drilling costs and the continued advance of deep drilling technology. In the Overthrust Belt, doubts about the magnitude of the resource center on the significance of the failure of explorers to find a giant field over the past 3 to 4 years. Also, areas such as the eastern Gulf of Mexico, the Southeast Georgia Embayment, the Georges Bank, and the Baltimore Canyon have been expensive failures thus far, and their eventual contribution to satisfying U.S. energy requirements is unknown.

Estimates of the recoverable resource potential in the frontier areas vary by up to 100 TCF or more (the USGS and PGC differ by nearly 30 TCF in their assessments of the eastern Gulf of Mexico, alone). In OTA's opinion, most of this variation can be eliminated only by further exploration and development.

5. The Potential of Stratigraphic Traps

Stratigraphic traps are barriers to petroleum migration formed by gradual changes in the permeability of sedimentary layers rather than by abrupt structural shifts and deformation of layers. Because the structural traps are easier to locate, they have been the primary targets for exploration. Some explorers claim that the potential for gas in subtle stratigraphic traps has been inadequately tested and predict that large resources remain to be found in "mature" areas (areas that have already been intensively explored) in these traps. Although this issue is not settled, the optimistic argument is weakened by observations that numerous stratigraphic traps have been found in the Permian Basin and elsewhere and that the extensive drilling in areas that appear to be good prospects for stratigraphic traps should have uncovered most of the larger traps, which generally are extensive in area. Though it may appear more likely than not that most of the remaining undiscovered traps will be small in volume, a possibility exists that larger fields may have remained hidden because of the less effective exploration methods used in the past and drilling that, while extensive, might have clustered in the wrong places or been too shallow. On balance, OTA concludes that it is quite possible that a few giant stratigraphic fields may remain to be discovered in the mature onshore areas of the Lower 48, but that it is unlikely that there are many such fields still undiscovered.

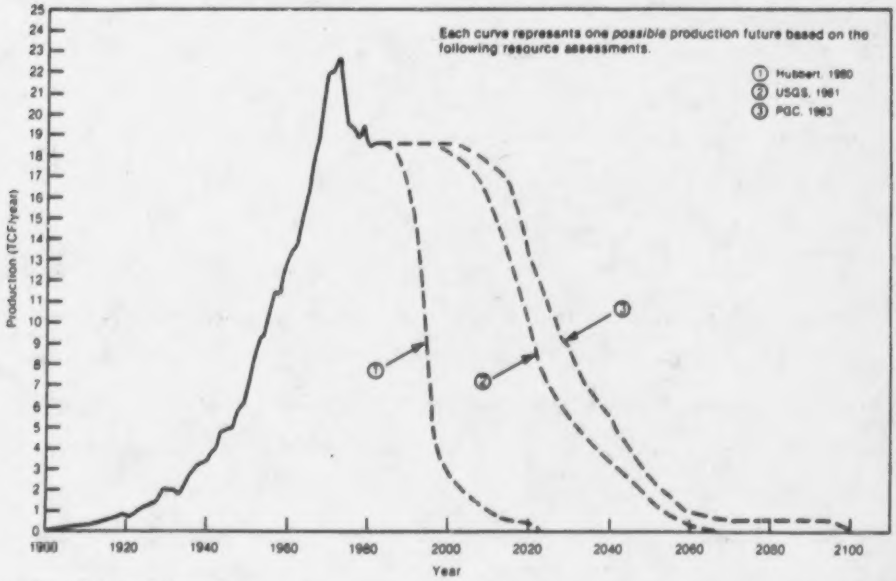
In addition to these five issues, a level of uncertainty is ever present in the process of estimating the quantity of a resource that cannot be measured directly prior to its actual production. The presence of economically recoverable concentrations of natural gas requires an unbroken chain of events or conditions, the presence or absence of which generally cannot be accurately predicted nor in some cases even measured directly. First, adequate amounts of organic material and suitable temperature and pressure conditions for gas formation and preservation must be present. Second, the gas must be free to migrate, and an adequate reservoir must be available in the path of migration to contain the gas. Finally, there must be a mechanism to trap the gas, and the trap must remain unbreached until the gas is discovered and produced. These sources of uncertainty account for the various manifestations of risk in natural gas development -- the large number of dry holes drilled during exploration, the often huge differences in bids for leases, the multimillion dollar failures of many of the leased areas, and the continuing disagreements over the size of the remaining resource.

In interpreting our estimates of the remaining resources of conventional gas, a word of caution is necessary. In describing the resource base I used the words "recoverable under present and easily foreseeable technological and economic conditions." To be more precise, this means that in estimating recoverable resources we are assuming that the price of gas does not go from its present market price of about $3.00/mmBTU up to, say, $10.00 or more. We also assume that technology may improve incrementally but not radically. Bounding our estimate by conditions such as these is necessary from a practical standpoint, and similar bounds are placed on most other estimates such as those of the USGS and PGC. However, it is well understood in the scientific community that the recoverable resource base is a dynamic concept. Over time, resources that are considered subeconomic or unconventional will move, gradually or sometimes abruptly, into the realm of conventional, economically recoverable resources as technology and scientific understanding change and prices rise. The contrary is also true, of course: resources can move out of the economically recoverable range as well, if prices drop.

Implications for Future Production

I stated at the beginning of my testimony that the upper and lower ends of our estimated range of conventional resources had strongly different implications for future domestic gas production. These implications can be illustrated by drawing curves of possible U.S. gas production histories assuming total resources at each end of our range. Figure 1 shows one possible production history for each of three estimates of remaining resources:

Figure 1 —Future Production Curves for Conventional Natural Gas in the Lower 48 States



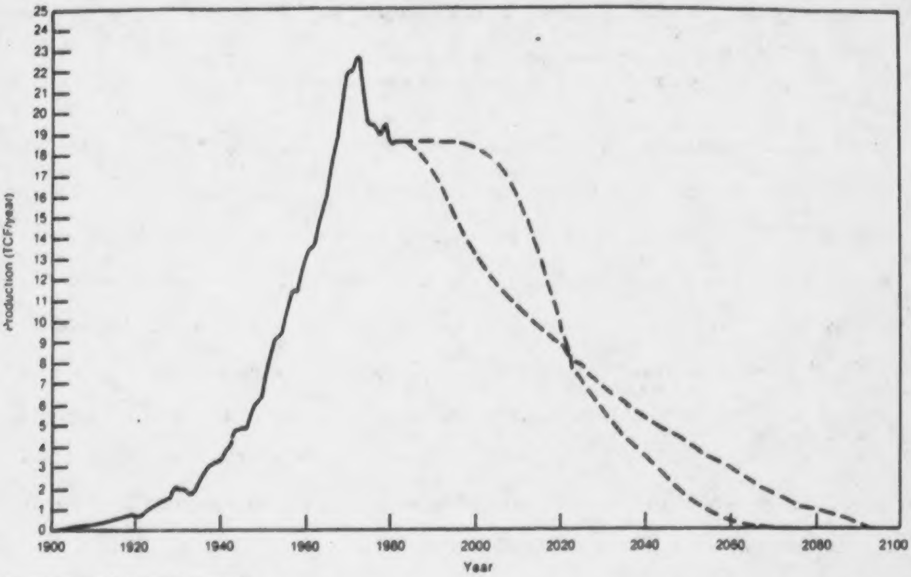
SOURCE: Office of Technology Assessment.

1. A 1980 estimate by L. King Hubbert, which actually is over 100 TCF below our most pessimistic estimate;
2. the 1981 USGS estimate, from Circular 860; and
3. the latest estimate of the Potential Gas Committee, which is about equal to the high end of our range.

There is no realistic way to draw curve 1 that would allow production to remain near current levels past the middle 1990's. In fact, the curve, as drawn, is probably unrealistic in that a more plausible production curve probably would drop more quickly in the late 1980's, and a bit more gradually thereafter. In any case, curve 1 -- and a curve representing the low end of the OTA range, as well -- represent a future where domestically produced natural gas from conventional sources has a sharply declining role as a major U.S. fuel source. I must note that the implications of the low end of OTA's range are at odds with the conventional wisdom, which foresees only a moderate decline in conventional production during this century as long as we do not find some way to thoroughly discourage the industry from doing the necessary exploration and development. This latter view is more compatible with the high end of OTA's range of resource estimates.

Curves 2 and 3 represent a future where conventional gas production continues at current levels for 2 or 3 more decades, probably enough time to begin to develop alternative sources of gas. It's important to note, however, that there are an infinite number of ways to draw these curves. For example, Figure 2 repeats Curve 2 of Figure 1 and adds another curve which shows how the same resource base can be produced at a different, more gradual pace. This latter curve reflects the conventional wisdom -- a gradual dropoff of conventional production, to 14-15 TCF/yr by 1990 and 12-13 TCF/yr by 2000.

Figure 2 .—Two Production Futures, One Resource Base: Alternative Representations of Future Production of Conventional Natural Gas in the Lower 48 States, Based on the USGS (1981) Resource Assessment (mean estimate)



SOURCE: Office of Technology Assessment.

Despite the available flexibility in drawing the production curves for the higher end of our range of resource estimates, it seems quite clear that the range encompasses radically different gas supply futures. The lower end represents a calamitous decline in gas production; the upper end presents at worst a gradual and probably manageable decline in production, and quite possibly a substantial breathing space in which to develop substitute fuels. Next I will review some of these alternative supplies.

UNCONVENTIONAL GAS RESOURCES

Resources that violate the technology boundaries of "conventional" gas supply are often called "unconventional" gas resources. In the course of our study we examined in detail three resource categories that generally are labeled as unconventional; gas from tight sands; Devonian Shales; and coal seams. It is important to note, however, that there are only minor differences in physical aspect and production methods between conventional resources and these unconventional resources.

Before discussing the individual categories, I should point out that the high degree of uncertainty OTA attaches to resource estimates involving conventional gas is magnified in our estimates for the unconventional resources. There is little or no production history to use as a guide, the baseline assumptions for estimating recoverable resources typically project future rather than current technologies, and the physical nature of the resource is certainly not as well-characterized as the conventional resource.

In the discussions that follow, we use the term "gas-in-place" to denote the total gas in formations where some economic gas production is feasible. This term is not defined consistently in the resource literature, with some authors including all gas in the earth regardless of whether or not any can be economically produced, and others placing strict economic and technical limits on the estimate.

"Tight sands" are formations of sandstone, siltstone, silty shale, and limestone that are characterized by their extremely low permeability, that is, fluids and gases do not flow easily through them. Because of this physical characteristic, economic levels of gas production can only be achieved by creating a man-made increase in permeability, by fracturing the reservoir rock surrounding the well-bore. This is most commonly achieved by hydraulic fracturing, which involves pumping a fluid under high pressure into the well until sufficient pressure is achieved to break down the rock. The fluids contain "proppants", usually sand or a harder material ("refractory"), that are left behind in the fractures to keep them open once the fluid pressure is removed.

Although FERC has defined tight sands as formations having permeabilities of less than 0.1 millidarcy (md), there is no widely recognized permeability boundary for resource estimates. Nearly 1 TCF of current U.S. production is generally considered as being derived from tight sands, however, and over 150 TCF of the PGC's estimate of the potential gas resource in the U.S. can be categorized as tight sands resources.

Although gas from tight sands generally is considered to be one resource, there are two distinct types of tight sands formations with significantly different producing characteristics. Blanket formations extend laterally over large areas, as befits their name. They occur either as one thick gas-filled layer or as many very thin layers alternating with clay-rich layers. Lenticular formations consist of many discrete reservoirs, often shaped like lenses, separated by shales and sometimes by coal seams. They occur stacked vertically one over the other, in formations hundreds of feet thick.

Estimates of the economically recoverable gas from tight gas formations may differ by a factor of 20. However, the tight sands are widely believed to be the most promising unconventional gas resource for the next few decades. The National Petroleum Council (NPC) estimated the recoverable resource to be 192-575 TCF depending on gas prices and available production technology. The less optimistic estimate of the Gas Research Institute is 30-150 TCF. Even

GRI, however, believes that tight gas will provide at least an additional 2 TCF/yr (beyond current production) to U.S. gas supply by 2000, and the NPC foresees at least 5 TCF/yr of production by 2000 even at gas prices no higher than today's.

OTA has examined the various estimates of tight sands recoverable resources in detail. As I noted previously, our conclusions are preliminary and they have not been completely reviewed. In general, we believe that gas from tight sands is a very promising resource, although we have some concerns about the resource estimates of the NPC. First, it appears to us that the NPC consistently chose the optimistic end of a range when they were faced with a choice of possible assumptions about the efficacy of recovery technology. For example, they assumed that fractures will remain open and retain high permeabilities for a full 30-year production span; that every attempted well stimulation will be successful; and that there will be no interference effects between wells. We are less sure than they that fractures in the lenticular formations -- representing 25 to 30 percent of their estimated recoverable resource -- will be able to consistently contact "lenses" distant from the wellbore, and that very long fractures can be consistently achieved in the shallow, low pressure blanket reservoirs of the Northern Great Plains. We believe that their estimate of 75-95 percent recovery of gas-in-place for the Northern Great Plains may be too high, and that 50 percent recovery might be more realistic. However, we also recognize that fracturing is still a relatively immature technology, and there exist substantial opportunities for improvements through research and development.

Second, there seems to be a fairly widely held view that the NPC's gas-in-place resource estimates -- from which the recoverable resource and production estimates were derived -- were overly conservative. A particular area of controversy is the NPC's choice of relatively low values for the thickness of gas-bearing intervals in the lenticular basins. There is also some controversy over the NPC's decision to exclude tight reservoirs below 15,000 feet from the resource base. The current PGC estimate for conventional resources includes some reservoirs of this type. These are areas of vigorous dispute in the industry, and some analysts hold precisely the opposite view, that the gas-in-place estimates are too high. Resolution of this and other important issues must await additional efforts at resource characterization and actual development of the gas resource.

Our conclusions do not contradict the basic thrust of the NPC report, that gas from tight sands represents a major incremental resource, albeit one that would benefit greatly from a focused research and development program to advance the state-of-the-art of fracturing and other production technologies and improve our understanding of the tight gas resource characteristics.

Devonian shale gas is gas produced from shales formed approximately 350 million years ago -- during the Devonian period of geologic time -- in a shallow sea that covered the eastern half of what now constitutes the continental United States. The shales occur primarily in the Appalachian, Illinois, and Michigan basins, but past production has primarily been in the Appalachian Basin, in the Big Sandy field in Kentucky.

Unlike conventional gas, Devonian shale gas did not migrate from organic-rich "source rocks" to reservoir rocks and accumulate in a trap. Instead, the low permeability of the shale prohibited most of the gas from escaping, and the shale thus acts as a source rock, reservoir, and trap for the gas. As with the tight sands, fracturing is used to overcome the low permeability of the reservoir and open up pathways for gas to flow to the wellbore. Hydraulic fracturing is difficult in the shales, however, because they contain clays that can expand and reduce permeability if exposed to water and other fluids. Therefore, explosive fracturing is still quite common, although hydraulic fracturing using non-water-based fluids is growing in use.

Estimates of the "gas-in-place" -- the gas physically present -- range from 400 to 3900 TCF, with the primary uncertainties being the differing measurements of shale thickness and disagreement about the amount of gas that is bound to the surface of the shale material and not "free." The estimates of recoverable resources are very much lower, however, from 4 TCF to over 50 TCF. For example, a relatively optimistic estimate (among existing estimates) is 39 TCF by the NPC for the Appalachian Basin, which assumes advanced technology and gas prices at $9.00/mmBTU in 1979 dollars. At $5.00/mmBTU, the NPC's estimated recoverable resources are 11-27 TCF depending on technology. Similar or even lower values are projected by other estimators such as Lewin and Associates, while an earlier (1977) study by OTA was somewhat more optimistic, projecting a recoverable resource of 23-38 TCF at $2.00-$3.00/mmBTU ($1976) for the most promising portion of the resource, the so-called brown shales. Consequently, based on existing estimates, Devonian shale gas appears to be a resource that may play an important but limited role in U.S. production -- up to about 1 or 1.5 TCF/yr of production by the late 1990's -- for a few decades. However, this level of production, and the estimate of recoverable resources upon which it depends, are extremely sensitive to technology development. From one point of view, achieving even these moderate levels may appear optimistic because technological improvements will be necessary that may appear unattractive to the larger operators who normally would undertake the necessary innovation. Also, changes will be required in the existing leasing practices in the shale areas, which tend to discourage coordinated drilling programs. From another point of view, however, the assumed production rates and recoverable resource associated with the use of "advanced technology" may seem overly modest when compared with the very large gas-in-place resource potential.

Coalbed methane is natural gas that was formed along with coal and is now trapped in the coal seams, either in the fracture network (called "cleat") in the coalbed or adsorbed on the coal. Approximately two-thirds of the resource is located in the west and mid-west, and the remainder is located in the Appalachian Basin. An unusual feature of this resource is that most coal seams are aquifers, and the pressure of the water in the seams prevents the gas from escaping from the coal and being produced. Consequently, large amounts of water often have to be pumped out of the wells before gas production can begin; sometimes, pumping may have to go on for months before any gas is produced. Also, because the major fracture systems in the coal are oriented in a vertical direction, simple vertical wells are not capable of intersecting multiple natural fractures unless artificial fracturing is induced; consequently, slanted or horizontal wells are preferred where they are practical. Finally, because desorption of the gas from the coal will not occur without substantially lowering the pressure in the seam, wells may have to be spaced much closer together than would be efficient for conventional gas production.

Both the economics and the problems associated with producing coalbed gas may be quite dependent on whether or not the coal is mineable. If it is, the pre-mining removal of the methane may ease problems associated with methane buildup during the mining operations. However, concerns about any adverse effect of the gas removal on mine safety -- especially if fracturing is induced -- may reduce or eliminate the economic value of the coal. It is not yet clear whether or not such safety concerns are justified. Legal disputes about mineral ownership may also complicate development of this resource.

Estimates of the total gas-in-place in U.S. coalbeds are variable, with major sources of uncertainty being a lack of knowledge about the gas content of various kinds of coals and the potential for gas escaping from the seams. The range of estimates for the total U.S. gas-in-place is about 300-800 TCF. However, much of the gas occurs in thin coal seams or is at too low a density in the coal for production. Taking these factors into account, the recoverable gas resource will be much lower, probably on the order of 30-60 TCF at relatively high gas prices (above $5.00/mmBTU) and considerably less at prices closer to today's. Consequently, the coal bed methane recoverable resource appears to be of the same order of magnitude as the Devonian shale gas resource. However, some projections of future production levels for coalbed methane foresee a shorter period of resource exploitation with a higher rate of peak production. For example, the NPC projection envisions a year 2000 production of over 2 TCF, albeit at a gas price approaching $9.00/mmBTU. Assuming a more moderate gas price and taking account of existing constraints, it seems reasonable to project a year 2000 production approaching 1 TCF if development proceeds smoothly.

As I promised in my introductory remarks, I'd like to briefly touch on three additional potential sources of natural gas.

Gas from geopressurized brines has been described by some commentators as representing a vast new gas resource capable of ensuring the adequacy of U.S. gas supply for many decades to come. Others, however, view this gas source as being much more limited, with recoverable resources being on the same scale as Devonian Shales, or perhaps lower. Geopressured gas is dissolved in brines under high temperatures and pressures, in aquifers underlying large areas of the Texas and Louisiana Gulf Coast. Producing the gas involves bringing the brine to the surface and separating out the methane, possibly also making use of the heat and hydraulic energy of the brine. The most common view of this resource is that it will not play a significant role in U.S. gas supply during this century, although the view is by no means unanimous.

Gas hydrates are an ice-like mixture of gas and water, called a "clathrate", found in deep permafrost areas and in sea floor sediments. There seems to be an enormous amount of it, although most of the evidence for its presence is indirect, for example, unusual patterns in seismic reflection data. This appears not to be a near-term resource. Virtually all observers agree that there are major technical hurdles to be overcome before any significant production could begin.

Finally, there is "deep earth gas", which supposedly lies beneath the impermeable basement rocks and originates from the venting of methane from the earth's core. The presence of this gas is the hypothesis of Professor Thomas Gold of Cornell University, based on a number of arguments concerning earthquake phenomena, the carbon/oxygen balance in the earth's crust, present theories of the origin of the solar system, the trace element composition of natural gas, and so on. Verification of Dr. Gold's theories could have important implications for the presence of large, untapped gas resources both in the non-sedimentary basins and , more importantly, below the basement rocks in gas-bearing basins.

SUMMARY

Upon examining a variety of natural gas resource base estimates and the arguments for and against different views of the U.S.'s gas resource potential, OTA concludes that the remaining resource uncertainties are too large to justify either an optimistic or a pessimistic view. For example, we believe that an appropriate range for the conventional resource base is about 430-900 TCF; the low end of this range implies a rapid drop in conventional gas production within a decade, whereas the high end, in its most optimistic interpretation, would allow production to continue at today's level for at least the remainder of the century. Similarly, we view the unconventional sources, especially the tight sands, as extremely promising but still highly uncertain as to their ultimate potential.

The high level of uncertainty regarding the natural gas resource base has important implications for public policy concerning the development of gas supplies and their utilization as well as the supply and utilization of competing energy sources. In particular, the resource uncertainty implies that a high value should be placed on policies that promote a flexible energy system that can respond rapidly and efficiently to emerging trends in gas supply, either up or down. Such policies might include bolstering the collection and interpretation of data on gas discovery and development, promoting research and development on unconventional gas sources and more efficient gas utilization, and providing market incentives to energy utilization technologies with multi-fuel capabilities.

Senator MURKOWSKI. Thank you very much for that excellent testimony, Mr. Plotkin.

Tell me, gentlemen, in your estimate and the figures that you have used, would you characterize that you have been conservative in those estimates as opposed to being optimistic, or nonconservative?

Mr. EVERED. Mr. Chairman, I think for the most part we have been able to talk in terms of ranges; the low side of which would be perhaps more conservative, and the high side perhaps more optimistic.

When we speak of means, or average figures, within those ranges, we attempt to convey the thought of equal likelihood on either side of that figure.

Senator MURKOWSKI. Well, would the rest of you generally agree with that? If there's anyone that would feel otherwise—I take it there is agreement.

Mr. Plotkin.

Mr. PLOTKIN. I would like to add one point, one thought. That is, I believe it's fair to characterize all of the estimates presented here today as being conservative in the sense that they focus on current technology, and they also focus on the current economics of gas production and the prices that people are willing to pay.

Senator MURKOWSKI. You're using USGS and Energy Information Administration figures, I gather?

Mr. PLOTKIN. Well, what I'm saying is that if you read the boilerplate of the USGS and the Potential Gas Committee estimates where they describe how they arrived at their figures, they are very careful to say "we're assuming prices that are similar to today's; we're assuming that the technology of production is similar to today's".

Now, I think it's inevitable that there will be advances in production. It may not be inevitable that prices go up, but if they do, that will change the estimates, that will raise them. And so I think that it really is fair to say that everybody's estimate here is conservative in that sense.

Senator MURKOWSKI. Everybody's basically using the same numbers.

Mr. PLOTKIN. The same assumptions.

Senator MURKOWSKI. That's correct; based on the current information, which is USGS and EIA. Is that right?

Dr. KENT. I think we would have to characterize the work of the Potential Gas Committee as using other sources as well. In many cases it's——

Senator MURKOWSKI. Yet your general conclusion is not that different.

Dr. KENT. Not that different. I think we're approaching it with a different group of people using different information.

Senator MURKOWSKI. Dr. Kent, in your testimony you made the statement that a sizeable portion of the resource potential, almost one-half, exists in areas which are relatively accessible and relatively inexpensive to develop.

In that were you including, or excluding Alaska?

Dr. KENT. I was excluding Alaska in that, and I was excluding it in terms of accessibility.

Senator **Murkowski**. As Alaska represents about one-fifth or one-sixth of the undiscovered, recoverable resources, then that would mean simply that that portion of the U.S. recoverable resources, about 665 Tcf, is considered accessible?

Dr. **Kent**. Yes.

Senator **Murkowski**. As opposed to the 107 Tcf in Alaska?

Dr. **Kent**. That's correct, because of the transportation problems there.

Senator **Murkowski**. I have a couple of other questions, gentlemen.

We all know the economics dictate when there is going to be an appropriate climate to encourage the exploration and development of these resources; that's the economic dictate of price and return on investment.

In view of what's happened in the United States in this last decade, from 1977 through 1982 where, as indicated, gas reserves fell from 175 Tcf to 167 Tcf, we still had an increase in the reserve-to-production ratio because of a decline in gas demand over that period of time. That reduction was 9.4 to 9.7.

Does this suggest, in your opinion, that the U.S. reserve picture is improving because of conservation, or is this in your opinion a temporary measure?

Mr. **Evered**. Mr. Chairman, that may reflect a dangerous misinterpretation of the reserve-to-production ratio.

You correctly point out that the R/P ratio went up recently because of the decline in production, which is demand constrained today.

The actual reserve inventory did not grow. In fact, had production remained at the same level in 1982 as in 1981, the R/P ratio would have dropped from about 9.1 to 8.9.

Senator **Murkowski**. Well, do you think—and I'll just ask anyone on the panel to answer this—as an inducement or an incentive, might we expect a reduction in the price of gas to result in larger usage of gas which would, obviously, encourage the exploration for more gas all things being equal, and all things aren't because you've got deep gas that costs more, so you wouldn't bring that in necessarily?

But how do you equate encouraging exploration and development of the resource, the undiscovered reserves that we know we have? Or do you just say the market will eventually dictate the pace and price of other fuels? Can you shed any enlightenment on whether we can assume that there will be some other factor than just the straight monetary economic dictate of expanding exploration?

Dr. **Kent**. Mr. Chairman, I think perhaps I can make a comment regarding that.

There is some concern expressed by those people with whom I work at the relatively rapid depletion of some of our large-volume gulf coast fields, and the lack of replacement with discovery of new fields in those areas, and a feeling that we are going to come to a place in which our productive capacity may be strained. In terms of what has been called a gas bubble—I don't know that that's a good expression, but I've heard estimates ranging from the fact that as early as next year we may have some problems in deliverability, depending on the weather and other factors; perhaps it may be a couple of years or so down the road.

But unless there is continued incentive for exploration and development, it's going to become increasingly difficult from our present fields to meet our demands.

Mr. **Evered**. Mr. Chairman, if I may.

Senator **Murkowski**. Yes.

Mr. **Evered**. The marketplace clearly is the most efficient mechanism for finding, developing, and delivering supplies of gas to consumers.

Suppressing prices artificially through regulation have the combined effect of stimulating gas demand, and suppressing the incentive to find new supplies to replace that demand.

Senator **Murkowski**. In your opinion, gentlemen, does the current lack of a market for Alaska gas adversely affect gas exploration in Alaska?

Mr. **Evered**. I would say yes.

Mr. **Offield**. I don't see how it could be otherwise, sir; but one of the things is that there's perhaps not that much direct exploration for gas anyway. Much of the exploration starts out for oil, and the gas is kind of a byproduct.

And one of the problems, of course, up there is that the smaller fields are not going to be produced.

Senator **Murkowski**. Well, by that same logic, can you assume then that if you went out and explored for gas as opposed to oil—cause I think it's fair to say that the gas that has been found in Alaska is a consequence of looking for oil, they haven't gone out and looked for gas.

If you have a market for Alaska gas, a way to transport Alaska gas, is it likely that the reserves undiscovered might be higher than the projections that we have of 107 Tcf, which are about a fifth or a sixth of our Nation's total reserves? Might they be increased if there were exploration for gas specifically?

Mr. **Offield**. It is difficult to say. When the USGS makes its estimates, we have a group of experts that call on all the geology they know in an area, and they consider, I think typically, more factors among estimators than most other groups tend to get at; but also, they are somewhat hamstrung by not having a lot of private industry data. Nevertheless, the estimate is probably quite real.

The important part may well be that it is bounded by an economic cutoff. There are assumptions there as to what the producibility beginning will be economically with field size. And if, for example, there were more active exploration and more active finding, then, of course, a pipeline or something like that, a delivery infrastructure might then follow, and that changes the economic picture rather fast.

One of the other things to remember, though, is that in places like the Navarin Basin, or any of these far-frontier areas, is that the typical numbers used, I believe in industry, are 9 to 14 years to bring a field on. So it is not something that you can start on today and have tomorrow.

Senator **Murkowski**. In my opening remarks I stated that I did not believe that Alaska gas can be marketed in the lower 48 until the Canadians no longer wished to export at the current level of Canadian gas.

And what I'm told is the estimate, keeping the cushion in reserve of 25 years for Canadian gas, that Canada has an estimated 400-year supply of gas. One wonders about the lifetime span of any one of us in ever seeing the economics dictate that Alaska gas might find its way into market, recognizing that the transportation system does not exist, as opposed to Canada where there is a transportation system in existence, and with the significant reserves associated with Canada and their inability to utilize that much gas.

What are, in your opinion, the economics when you throw it into the entire U.S. reserves? You can make certain assumptions when you consider the marketing of Alaska gas standing on its own, I assume, you have to consider those assumptions as directly related to what might be the competing factors, and Canada has already established itself in that posture.

I would appreciate any generalized comments you would care to make.

Mr. Plotkin?

Mr. PLOTKIN. Mr. Chairman, the current conventional wisdom, I guess it is reasonable to say, about conventional gas production in the year 2000 is that we're likely to have a production in the range of 11 to 15 Tcf. OTA feels the range of uncertainty is somewhat wider than that, but most forecasts put it in that range.

If this Nation is going to use about the same amount of gas in that time, we're going to need additional supplies, not only from our current imports from Canada and Mexico, but also from unconventional sources. And if they don't pan out as well as some people hoped, perhaps we will want to make up the difference from Alaska. I think the key is what is going to happen to these competing sources? Will unconventional gas sources be able to be developed at low prices? For example, the forecasted price of Alaskan gas and the forecasted price of some of the unconventional sources are in the same ballpark, and it's not really clear which is going to be the more competitive.

So in the future if we need that gas, it certainly is possible that we may have the wherewithall to build that pipeline, but at this point in time I think it's really impossible to predict it.

The second point is that——

Senator MURKOWSKI. And when you say "to predict that"——

Mr. PLOTKIN. To predict whether or not one source, some of the unconventional sources, like Devonian shale, or some of the more difficult tight-sands gas, are going to be cheaper or more expensive than Alaskan gas will be.

The second point is to look at the demand side for a minute. I think it's fairly easy to see a future where we might want to use more gas, perhaps to back-out imported oil.

Senator MURKOWSKI. That depends on price again though.

Mr. PLOTKIN. Not only on price, but also on the reliability of the sources, which is impossible to forecast.

But there certainly is a reasonable probability that we may want to increase our gas production to a level which is beyond what the current sources are capable of producing, so that Alaskan gas could then fulfill that portion of our energy requirements.

Senator MURKOWSKI. Well, from a competitive analysis, you look at Alaska gas entering into the market—there's two potential competitors. One is already established, and that's Canada; and Mexico is shipping about 1½ Tcf currently.

I'm curious to know, are the Canadian figures and the figures from Mexico—2.3 Tcf for Canada, 1.5 Tcf from Mexico, are those substantially on the increase, if you're doing an analysis over the last 5 to 10 years, are they on the increase?

Mr. EVERED. No, they are not, Mr. Chairman.

Senator MURKOWSKI. They're not. Are they relatively stationary?

Mr. EVERED. In recent years, exports to the United States from Canada have dropped quite a bit. Mexican exports have also been declining. My understanding is that Canadian sales to the United States have declined in the face of their clearly over-market price. But I would say that——

Senator MURKOWSKI. Over-market price, or less utilization as a consequence of the economics and demands?

Mr. EVERED. The two are inexorably linked.

Senator MURKOWSKI. But has the gate price increased, the entry price?

Mr. EVERED. No. In fact, the Canadians recently have made some price concessions to U.S. buyers who might increase their import volumes. Indeed, the price that had been set under earlier policy has turned out to be higher than that which allow them to market the volumes that they had authorized.

I would say that the chairman's concerns for the strength of the market position of the Canadians vis-a-vis Alaska gas coming to the lower 48 are well founded.

Senator MURKOWSKI. And you mean in that specifically what?

Mr. EVERED. That the Canadians have a potentially large amount of gas that they could sell to U.S. lower 48 markets, if they chose to, at prices which are set as a matter of government policy in Canada.

Senator MURKOWSKI. I've had an occasion to have informal discussions with various Members of Parliament in Canada, and we have talked about the export of Alaska gas and the continued importation into the United States of Canadian gas into those markets and the construction of the Alaska Gas Transportation System.

Of course, they expressed an interest in both continuing to export Canadian gas into the United States, and to see that that pipeline was built.

I've asked them which one they would prefer if they couldn't have both, and a few of them grudgingly admitted that they wanted to keep selling gas into the United States even at the expense of their interest in seeing that pipeline built.

They're selling that gas now through the pre-build line, and they want to continue that. And I think it's fair expression, if they had to have a choice, that choice would mean to keep selling Canadian gas, and it would mean, of course, the ANGTS line would not be built.

Of course, we have assisted in the construction of the pre-build, and the economics dictate that the markets for Canadian gas are in the United States, because it's simply closer to supply and less costly, and that's going to dictate, to a large degree, the realities of exporting gas into the United States from that source.

But what I think you gentlemen have done through your testimony indicated that there is a substantial reserve of the resource in North America, and with the predictions of the increased usage of that gas are dependent on so many factors, it's pretty hard to make even a generalization.

I think it's certainly startling to reflect, at least from a parochial interest in the ANGTS line, that Canada, with its substantial reserves, is certainly in a position where they very well may wish to continue supplying an undetermined amount of gas to the United States, which certainly has the opportunity to displace the ability of Alaska gas to find a market. And that leaves us with the alternative question of, what do you do if, indeed, you wish to market Alaska gas at this time?

We are going to have the hearing record remain open for approximately 2 weeks. There may be other questions that we would submit to you.

I want to thank all of you for your excellent testimony. Obviously, there has been a great deal of research and hard work in the preparation. It will assist us substantially, I think, in putting together a very detailed record that will stand the test of those who will examine it.

I thank you, gentlemen, and I wish you a very good day.

The nest panel will present itself to the witness table. Mr. Charles B. Wheeler, senior vice president, Exxon Corp., U.S.A.; Mr. Jaye Dyer, president and chief executive officer of Dyco Petroleum Corp.; Mr. Erving Wolf, chairman of the board and president, Inexco Oil Co.—Inco——

Mr. **Wolf**. In—ex—co.

Senator **Murkowski**. Ah, it had to be the third one.

Mr. **Wolf**. Do you want to try again?

Senator **Murkowski**. No. It shows you what Exxon has done around here. It makes everybody mispronounce everything else.

Mr. **Wolf**. We're more confused with Texaco, they use our credit cards.

Senator **Murkowski**. OK. Mr. Robert A. Hefner III, president and chief executive officer, GHK Co. We don't have to pronounce that one. Mr. Jim Jensen, president of Jensen Associates.

We welcome you before the committee on energy regulation, subcommittee of the full Committee of Energy and Natural Resources.

And assuming that you have no other desire than to go in the order which I presented you—if you do, why the first witness can jump up and grab the microphone; and, if not, I guess we will call on Mr. Wheeler, senior vice president of Exxon.

I might add, that the first panel managed to handle this in a little more than a hour and 15 minutes, and I would encourage you gentlemen to do the same.

Excuse me, Mr. Wheeler.

STATEMENT OF C.B. WHEELER, SENIOR VICE PRESIDENT, EXXON CO. U.S.A.

Mr. **Wheeler**. Thank you, Senator.

I welcome the opportunity, and Exxon appreciates the opportunity to review the status of the country's natural gas reserves and discuss the possibilities for future reserve additions.

I think we have—and I will sketch over some of my prepared text here in that it has been covered by previous speakers.

But I would like to point out—I believe you had expressed some interrest in the Point Thompson field in which Exxon has a substantial participation. I would say that our estimate of reserves in the Point Thompson field is approximately 5 Tcf, but this is not included in any proved reserve numbers that are shown for Alaska; in other words, this approximately 33 Tcf reserve does not account for Point Thompson, as it has not yet been proven to be economically recoverable.

Senator **Murkowski** By it's volume, or otherwise?

Mr. **Wheeler**. Well, based on its productivity, its location, the absence of outlet, all of these factors, of course.

I would also point out that the Prudhoe Bay constitutes 26 Tcf of the 33 proved in alaska, and 13 percent of total U.S, gas reserves.

In a handout which I have in my submission, I have two charts which show a declining trend in U.S. gas resources. These charts show that it is getting progressively more difficult to find new gas fields in the U.S., and that recoveries per gas well are smaller on average than in the past.

Several members of the first panel and yourself have observed the decline in proved reserves since 1970. I would only point out that this decline has occurred during a time in which drilling has increased fourfold over what it was on average in the 1960's.

So we have seen a substantial decline in reserves, and at the same time we have seen a substantial increase in drilling.

This confirms the point that it's getting harder to find reserves in the United States.

Senator **Murkowski**. When you use this chart of the U.S. reserves, are you including Alaska?

Mr. **Wheeler**. Yes. And that accounts for the uptick in reserves in 1970.

The second chart shows that the average recovery of gas per well has dropped significantly since the early 1970's.

In the 1950 to 1965 period, the average was in the 4 to 5 Bcf range, but in recent years it's hovered around the 1 Bcf level, and in 1982, it dropped to about three-quarters of billion cubic feet per well.

Reserve adds for 1983 were not available to us when this paper came out, but in the absence of very large announced gas discoveries, I understand there has been a slight decrease in the overall reserves.

Historic data show also that the size of discovery per exploratory well has declined dramatically with time.

So this point, we have been speaking about estimates of past and present proved reserves and the assessment of historic drilling results, which are based on known facts, and have a fairly limited margin of error.

On the other hand, I'll now turn to assessments of the amount of its yet-undiscovered gas, which requires a number of technical assumptions and are a very relative measure.

Qualified people may consider the same data and come up with widly differing assessments.

But it is true that the larger the data base, the more apt we are to be directionally correct in our assessment. And I would say that Exxon does have a large data base, and we have made use of it in an almost-completed assessment of the undiscovered gas potential in the United States.

Based on this new work, we estimate the volume of as-yet-undiscovered gas from conventional sources in the United States to be about 300 Tcf.

Our assessment can perhaps better be expressed by a range of possible outcomes. For example, we're quite certain that industry will find close to 200 Tcf, and we see a faint chance of finding as much as something over 600 Tcf.

The 300 Tcf represents a weighted average of the possible values.

The range expresses the uncertainties of industry's success or failure in extending known plays, and in the exploration of little-known frontier basins, and it illustrates the importance of continuing with an active exploration program to determine the extent of our gas reserves and the long-range availability of future supplies.

There are some changes in detail in our new gas resource estimate versus the last published assessment, which came out in 1976.

This is because we have large amounts of new technical data, and because the economics of oil and gas exploration and development have changed greatly in the interim.

However, the bottom line of both estimates is the volume of resources potentially available to the economy—and we call this the attainable resource. And on this basis, the two assessments are very close.

Also, our new gas resource base estimate is not out of line with other assessments made by private companies.

Shall I continue?

Senator MURKOWSKI. Please excuse me, Mr. Wheeler.

Mr. WHEELER. Yes.

If we're to find these undiscovered gas resources, the task will not be easy or quickly completed. The trend I showed earlier in gas reserves and in gas recoveries per well demonstrate that it will take decades of intense exploratory and development effort by industry, and hundreds of billions of dollars of investment to find these resources and bring them to market.

A favorable business in regulatory climate, including broad access to Federal lands, both onshore and in the OCS where much of this gas will be found, and freeing up of gas prices will be necessary to assure these domestic resources are found and developed in a reasonable time period.

I'd like to touch briefly on the need for these future gas supplies, some of which will be remote and require substantial investments to bring to market.

Our studies all indicate that for any reasonably, likely, undiscovered gas volume, the future demand for gas will exceed the supply available from the domestic resource base.

Today's current surplus of gas delivery capability is a transitory phenomenon. Lower 48 gas reserves are continuing to decline. And even with only modest growth in demand, requirements for natural gas will significantly outstrip domestic supply capability by the late 1980's.

By the 1990's, we project that an increasing proportion of U.S. gas supplies will come from imports or synthetics; all generally more expensive than conventional domestic gas.

In addition, we project the shortfall of economically available gas from any source, and this will probably require substitution by increased oil imports.

A key additional energy source to help fill U.S. energy needs, and limit oil import growth after 1990 will be Alaskan gas reserves.

Efforts to make this resource available to lower 48 markets must continue to receive high priority, and we support an active program in this area.

Our present proved reserves to production ratio for gas is only about 10.8 years. And without Prudhoe Bay gas, this figure drops to around 9.4 years for 1982.

The challenge to industry and to Government policymakers will be to minimize, or hopefully, to prevent decline in our Nation's gas reserves and productive capacity.

Clearly, prudent policy should foster continues exploration.

And it is vital that we maintain the current OCS leasing schedule, as there are still large fields to be found in Federal waters.

Removing price controls, and allowing natural gas to freely compete in the energy marketplace is a needed component of public policy.

Furthermore, it seems prudent to conserve our scarce gas resources.

Senator, that completes my testimony, and I thank you for the opportunity to review this subject.

[The prepared statement of Mr. Wheeler follows:]

STATEMENT OF C. B. WHEELER
SENIOR VICE PRESIDENT, EXXON COMPANY, U.S.A.
BEFORE THE SUBCOMMITTEE ON ENERGY REGULATION,
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE
APRIL 26, 1984

I am C. B. Wheeler, Senior Vice President of Exxon Company, U.S.A. I am a geologist by profession and part of my area of responsibility includes Exxon's domestic exploration program for oil and gas. Exxon appreciates the opportunity to review the status of this country's natural gas reserves and discuss the outlook for future reserve additions.

The current EIA estimate is that proved gas reserves in the United States are about 201 trillion cubic feet (TCF). These reserves are located as follows:

Inland Lower 48	128 TCF
Offshore Lower 48	40 TCF
Alaska	33 TCF

The Alaskan reserve includes an estimated 26 TCF in the Prudhoe Bay Field, but does not include an estimated 5 TCF in the Point Thomson Unit as it has not been determined that this gas can be produced economically. The Prudhoe Bay reserve constitutes 13% of total proved U.S. gas reserves.

I have two charts which show a declining trend in U.S. gas resources. These charts show that it is getting progressively more difficult to find new gas fields in the U.S. and that recoveries per gas well are smaller on average than in the past. The first chart plots the total proved reserves by year for the period 1950-1982. It also shows the number of gas wells completed each year for the same period. The 1965-1970 period was our peak, with reserves in the 280-290 trillion-cubic-foot range. Gas well completions at that time averaged about 4000 per year. You may recall that 1970 was the year that Prudhoe Bay reserves were booked.

Subsequent to 1970 the picture is one of steadily declining reserves until 1979, when reserves stabilized at about 200 TCF.

While gas reserves have declined sharply, the drilling effort to add new reserves has escalated enormously. Drilling reached a peak of almost 19,000 completions in 1982. Since 1982, there has been a sharp decline in industry drilling, resulting in an 18 percent drop in gas-well completions last year to fewer than 16,000.

The second chart shows that the average recovery per gas well has dropped significantly since the early 1970s. In the 1950-1965 period the average was in the 4 to 5 billion cubic foot range. In recent years it has hovered around the 1 billion cubic foot level, and, in 1982, dropped to about three quarters of a billion cubic feet per well.

Reserve add numbers for 1983 are not yet available, but in the absence of any very large announced new gas field discoveries, it is fair to assume that the average recovery per well will continue to decline, as will total new gas additions.

Also, historic data show that the size of discovery per exploratory well has declined dramatically with time.

To this point I have been speaking about estimates of past and present proved reserves and the assessment of historic drilling results, which are based on known facts and have a fairly limited margin of error. On the other hand, I will now turn to assessments of the amount of as yet undiscovered gas which require a number of technical assumptions, and are a very relative measure. Qualified people may consider the same data and come up with widely differing assessments. It is true, however, that the larger the data base, the more apt we are to be directionally correct in our assessment.

Exxon does have a large data base, and we have made use of it in an almost completed assessment of the undiscovered gas potential of the United

Based on this new work, we estimate the volume of as yet undiscovered gas from conventional sources in the United States to be about 300 TCF. Our assessment can perhaps better be expressed by a range of possible outcomes. For example, we are quite certain that industry will find close to 200 TCF, and we see a faint chance of finding over 600 TCF. The 300 TCF represents the weighted average of all of the possible values. The range expresses the uncertainties of industry's success or failure in extending known plays and in exploration of little-known frontier basins. This illustrates the importance of continuing with an active exploration program to determine the extent of our gas reserves and the long range availability of future gas supplies.

There are many changes in detail in our new gas-resource estimate versus our last published assessment which came out in 1976. This is because we have large amounts of new technical data and because the economics of oil and gas exploration and development have changed greatly in the interim. However, the bottom line of both estimates is the volume of resources potentially available to the economy, which we call the attainable resource; on this basis the two assessments are very close. Also, our new gas-resource-base estimate is not out of line with other assessments made by private companies.

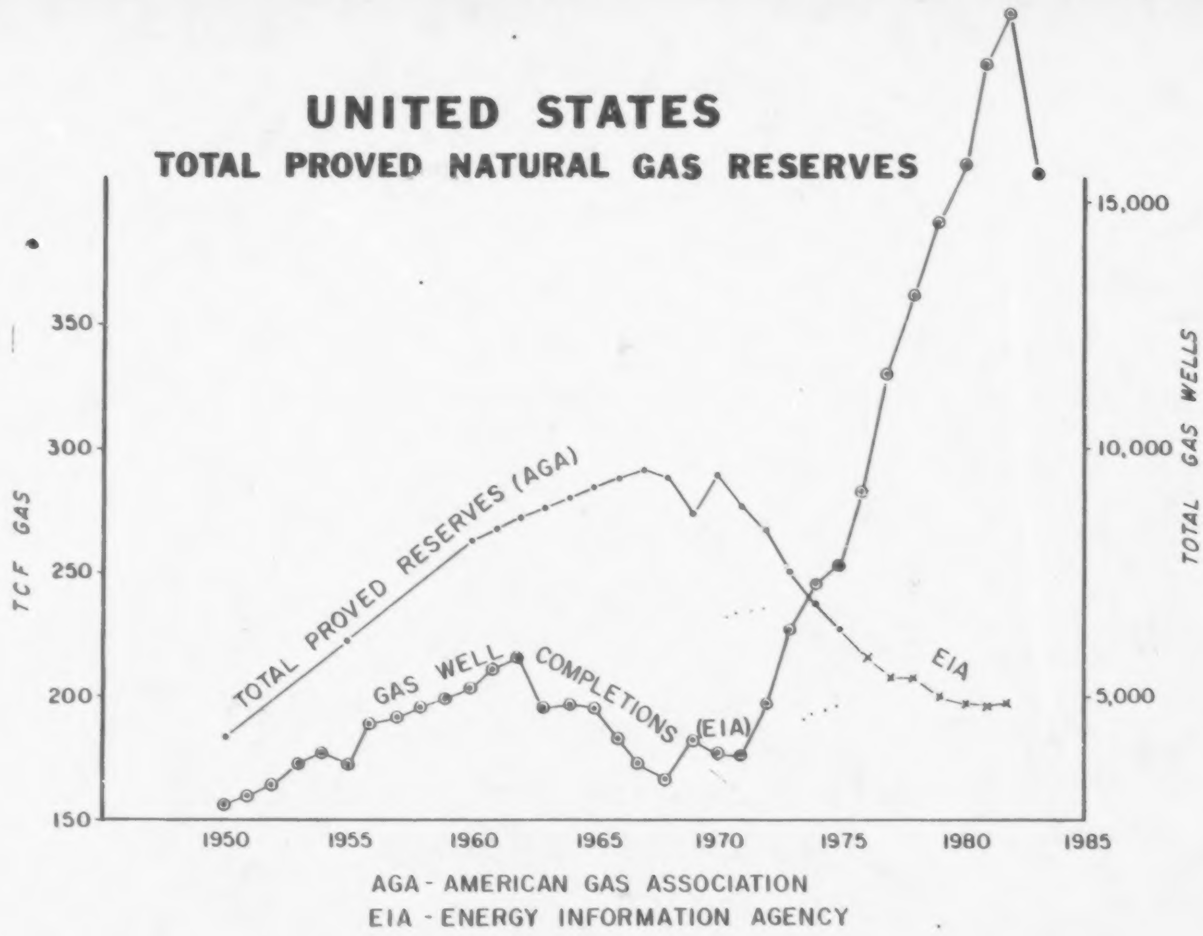
If we are to find these undiscovered gas resources, the task will not be easy or quickly completed. The trends I showed earlier in gas reserves and gas volumes per well demonstrate that. It will take decades of intense exploratory and development effort by industry and hundreds of billions of dollars of investment to find these resources and bring them to market. Favorable business and regulatory climate, including broad access to Federal Lands both onshore and in the OCS where much of this gas will be found, and freeing up of gas prices will be necessary to assure that these domestic resources are found and developed in a reasonable time period.

Let me touch briefly now on the need for these future gas supplies, some of which will be remote, and require substantial investments to bring to market. Our studies all indicate that for any reasonably likely undiscovered gas volume, the future demand for gas will exceed the supply available from the domestic resource base. Today's current surplus of gas delivery capability is a transitory phenomenon. U.S. Lower 48 gas reserves are continuing to decline, and, even with only modest growth in demand, requirements for natural gas will significantly outstrip domestic supply capability by the late 1980s. By the 1990s, we project that an increasing proportion of U.S. gas supplies will come from imports or synthetics, all generally more expensive than conventional domestic gas. In addition, we project a shortfall of economically available gas from any source; this will probably require substitution by increased oil imports.

A key additional energy source to help fill U.S. energy needs and limit oil import growth after 1990 will be the Alaskan gas reserves. Efforts to make this resource available to Lower 48 markets must continue to receive high priority, and we support an active program in that area.

Our country's present reserves to production ratio for gas is only 10.8 years. Without Prudhoe Bay gas, this figure drops to 9.4 years. The challenge to industry and to government policy makers will be to minimize or hopefully to prevent decline in our nation's gas reserves and productive capacity. Clearly, prudent policy should foster continued exploration. It is vital that we maintain the current OCS leasing schedule, as there are still large gas fields to be found in federal waters. Removing price controls and allowing natural gas to freely compete in the energy marketplace is an needed component of public policy. Furthermore, it seems prudent to conserve our scarce gas resources.

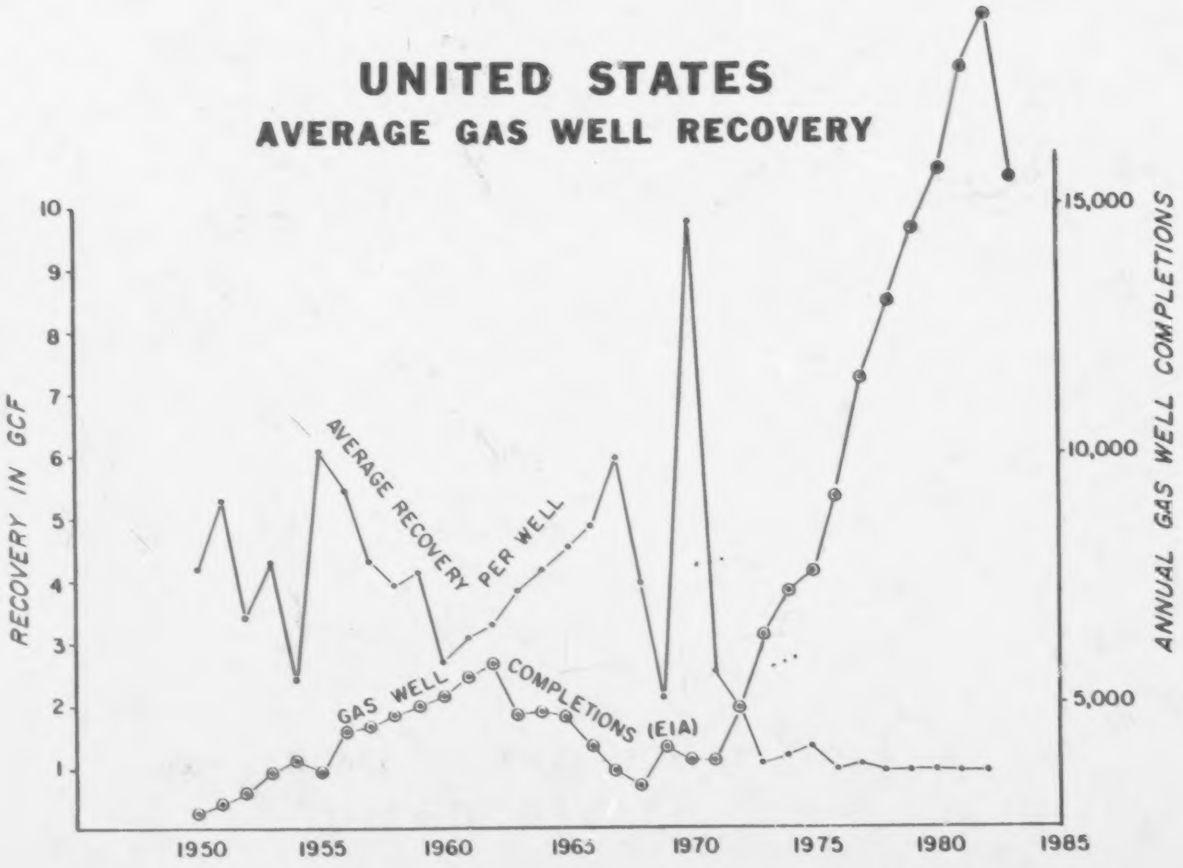
Thank you for the opportunity to discuss this important subject.



UNITED STATES
TOTAL PROVED NATURAL GAS RESERVES

AGA - AMERICAN GAS ASSOCIATION
EIA - ENERGY INFORMATION AGENCY

UNITED STATES
AVERAGE GAS WELL RECOVERY



Senator Murkowski. Thank you very much.

I'm going to depart from the pattern which I established with the first panel and ask the questions as I go along, because it's easier for me to keep them in mind. That's one of the advantages of chairing, you can change the rules.

I'm curious to know. In your testimony, Mr. Wheeler, you indicated that future demand for gas will exceed the domestic supply resource base, and you indicated further in conclusion that you feel that Alaska gas reserves will be needed to help fill U.S. energy needs and limit oil import growth about that time.

I believe your company holds about 70 percent of Imperial, which is a Canadian subsidiary which has substantial reserves in the Canadian Arctic, the Canadian Beaufort, and so forth.

Do you have available the magnitude of those reserves?

Mr. Wheeler. Well, I would say put it this way, this supply picture that I explained to you, Senator, included our assessment of the Canadian industry reserves as well as our own Imperial Oil Co. reserves.

Senator Murkowski. Well, the figure that I read in my opening statement that indicated that Canada could perhaps export at projected levels into the United States and still maintain that 25-year cushion for as much as 400 years would include, obviously, your gas reserves both proven and undiscovered.

Mr. Wheeler. Well, I guess what I'm telling you is that our numbers don't confirm the 400 Tcf, and I'm not really in a position to give you a number which has been developed by our affiliates up there. But our supply picture does include an assessment of both undiscovered and discovered resources in Canada.

Senator Murkowski. Well, your figures on page 3 indicated that you felt that the industry would find close to 200 Tcf. And the previous panel indicated that current U.S. reserves were 167 Tcf, and undiscovered resource reserves in the United States were estimated to be 665 Tcf. And you indicated you see a faint chance of finding over 600 Tcf.

So I guess it's fair to say that your estimates are rather conservative.

Mr. Wheeler. Well, I think really compared to what we heard, they're obviously much more conservative than some of the other people before me.

Senator Murkowski. Are you aware of what your reserves currently are in the Canadian Arctic, Western Canadian Arctic?

Mr. Wheeler. Our own reserves?

Senator Murkowski. Well, those that are controlled through Imperial, the ownership of Imperial.

Mr. Wheeler. Well, I don't know whether I have those with me, Senator, or not. I may have some that I could give you.

Senator Murkowski. Well, we would appreciate it if you would be kind enough to provide them for the record.

Mr. Wheeler. Certainly.

Senator Murkowski. Let me ask you another question.

There's been a proposal that has been talked about for some time called "the Dempster Lateral," which would potentially bring gas down from the Canadian Arctic to White Horse and then hook into that portion of the ANGTS which would be White Horse and south, and that would hook into the prebuild at Calgory.

Would not that be an opportune market alternative for your gas holdings in the Canadian Arctic as opposed to bringing gas down from Alaska?

Mr. **Wheeler**. Well, certainly that might be one alternative for moving Arctic gas along with Alaskan gas, that's true.

I think that some of the numbers you quoted of Canadian resources presume bringing Arctic gas down to the United States via some route or other. That raised a question we might all consider; namely, if it's hard to bring Alaskan gas in, why can the Canadians bring their Artic gas in cheaper and easier than we can?

Senator **Murkowski**. Well, it's obvious that one answer that's significant is that all of it, all of Canadian gas is closer to market. The second obvious answer is that much of it is already served by a pipeline, while no Alaska gas is served by a pipeline.

Mr. **Wheeler**. Well, none of the Arctic gas is served.

Senator **Murkowski**. In view of your extensive holdings in both the Canadian Arctic and the Prudhoe Bay field, do you have a priority within your corporation as to which gas you want to move first?

Mr. **Wheeler**. No, we have no such priority. We're interested in developing markets for both sources of gas. We have more extensive reserves at Prudhoe Bay.

Senator **Murkowski**. As an owner-company individually as opposed to the holdings you hold through Imperial. Is that correct?

Mr. **Wheeler**. In Prudhoe Bay, that's correct.

Senator **Murkowski**. But again, you've got—well, let me phrase the question a little differently.

Have you had an opportunity to review any economic analysis of which development would economically be more advantageous to the Exxon Corp. which holds 70 percent of the outstanding stock of Imperial from the standpoint of a comparison as to which gas would likely go to market first?

Mr. **Wheeler**. No, I have not seen any such analysis.

Senator **Murkowski**. That would be very interesting to see, because obviously you have, you know, two potential supplies and both can go into the market simultaneously, if the economics, of course, support it, and if they don't, one or the other, or neither, may go in.

Mr. **Wheeler**. That's true.

Well, Senator, of course, our belief is that both supplies are going to be needed, and that's the sense of my testimony; that they're both going to be needed. I'm not sure which will come on first.

Senator **Murkowski**. And you estimate that 1990 or thereabouts would be when you feel—do I understand both supplies would be marketed, or the Alaskan resource would be marketed?

Mr. **Wheeler**. Well, it's difficult to presume that the Alaskan pipeline could be completed as early as 1990, Senator. And I think the comment was as sort of a benchmark time, by 1990, we would increasingly be requiring imports, and perhaps by that timeframe a pipeline could be under construction from either one or both sources.

Senator **Murkowski**. Your corporation being a substantial owner of gas, do you have an interest in where the gas is marketed, or only if it's sold at what you would consider a reasonable profit—or there might be an alternative of liquefying that gas?

Mr. **Wheeler**. Well, our interest, of course, is finding a market for the gas, and also, obviously, to do so at the most attractive market that's available.

Our belief is that the alternative of liquifying the gas, including the cost of building a pipeline through the hostile environment where the gas, such as Prudhoe Bay, is now located, and then suffering the cost of building a liquefaction plant that that gas will not be competitive with world gas elsewhere placed in the world market.

Senator **Murkowski**. Do you have any figures internally that you could provide the committee to substantiate the statement which you have made?

Mr. **Wheeler**. I will investigate that and get back to you.

Senator **Murkowski**. We would appreciate having that for the record. And I understand that you will submit for the record your recollection of what your holdings are in the Canadian Arctic, both proven and undiscovered recoverable.

Mr. **Wheeler**. Well, I'm not sure that I can release to you our undiscovered estimates, but——

Senator **Murkowski**. Well, whatever is public knowledge.

Mr. **Wheeler**. Certainly our public knowledge will be presented, plus whatever else.

Senator **Murkowski**. All right. I very much appreciate that, Mr. Wheeler.

[Subsequent to the hearing Mr. Wheeler supplied the following information:]

EXXON COMPANY, U.S.A.
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C. B. WHEELER
SENIOR VICE PRESIDENT

May 18, 1984

Subcommittee on Energy
Regulation Oversight Hearing on
Marketing Alternatives for
Alaska North Slope Natural Gas
April 26, 1984

Honorable Frank H. Murkowski, Chairman
Subcommittee on Energy Regulation
Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20510

Dear Senator Murkowski:

During the hearing before the Subcommittee on Energy Regulation of the Committee on Energy and Natural Resources on April 26, 1984, you asked that I submit for the record additional information on two subjects. This letter responds to your request.

You inquired about the proven natural gas reserves of Imperial Oil Ltd. in the Canadian Arctic. You specified the western Canadian Arctic. As of December 31, 1983, Imperial's proven natural gas reserves in the Mackenzie Delta are approximately 3 trillion cubic feet. Such reserves are located primarily in the Taglu Field.

You inquired about Exxon's assessment of the commercial viability of exporting Alaskan liquefied natural gas (LNG) to markets on the Pacific Ocean, primarily Japan. Exxon is in the business of selling natural gas under commercially sound terms at the best price obtainable. We are concerned that we sell our gas into the best long-term market. Our assessment is that over the long-term -- 20 years or more -- LNG from the North Slope of Alaska would be at a competitive disadvantage in Japan and other Pacific markets with LNG from other sources. The prospective LNG market in Japan is small compared to potential supply. We expect that over the long-term there will be LNG from several other sources, much closer to Japan than is Alaska, which can be delivered at much less cost than could LNG from Alaska. Gas from such other sources would not be burdened with the cost of more than 800 miles of pipeline through difficult Arctic terrain prior to being liquefied and loaded on tankers for shipment.

Over a period of several years, we have repeatedly examined alternative methods for marketing Prudhoe Bay gas, including the LNG export alternative, and have consistently concluded that an overland pipeline such as the ANGTS is the best means of marketing Prudhoe Bay gas. As mentioned by Mr. S.J. Reso in his response, dated January 16, 1984, to your additional questions, we are willing to share the results of our studies with appropriate government representatives under arrangements that will protect proprietary information.

You commented upon the disparity between Exxon's latest estimate of the undiscovered potential natural gas reserves in the United States and the much greater estimates presented by others who appeared before the Subcommittee. Exxon's estimate is more conservative than the other estimates, beyond doubt. The critical question is not which estimate is most accurate but rather, what are the consequences if the nation relies upon the more optimistic estimates, becomes committed by international agreements and huge investments to an LNG export project, and later discovers the optimistic estimates to be wrong. In such circumstances the nation might face gas shortages and increased reliance upon imported oil.

In reviewing the draft transcript of the hearing of April 26, 1984, I found the need for minor corrections and changes in the record of my remarks. Forwarded herewith are copies of pages 54, 61, 62 and 74 of the draft transcript on which I have noted the corrections and changes needed.

Thank you again for the opportunity to appear before the Subcommittee. If additional information is needed, please advise accordingly.

Yours very truly,

Senator MURKOWSKI. Our next witness is Mr. Jaye Dyer.

Mr. Dyer, we welcome you to the committee, and look forward to your testimony and would ask that you proceed.

Mr. Dyer is president of Dyco Petroleum Corp.

STATEMENT OF JAYE F. DYER, PRESIDENT AND CHIEF EXECUTIVE OFFICER, DYCO PETROLEUM CORP.

Mr. DYER. Thank you, Mr. Chairman.

I appreciate being here and being able to participate in this examination.

I'm going to briefly summarize my statement which I have submitted for the record.

Senator MURKOWSKI. It will be entered into the record.

Mr. DYER. Our company is principally engaged in natural gas exploration. We're an active, independent company, and we operate in the Anadarko basin of Oklahoma, throughout the Rocky Mountains States, and into Alaska, where we currently have two operations—nonoperating operations underway.

I appreciate the testimony of the prior panel members in their efforts to establish the sound estimates of our size of our potential reserve base.

I submit, however, that it's unfortunate, but all the skills they have cannot accurately measure that without a great deal more drilling.

Historically, I think it's fortunate that most estimates over the past have proven to be conservative, and I suspect that the estimates today will prove to be understated.

From our company's perspective, we started in 1971, and we believed then that the natural gas was underpriced and underappreciated. By the 1980's, we had received prices very near parity with oil, but we still believe natural gas is underappreciated.

To help us in your planning, we engaged a reputable firm of economists to do an econometric study of natural gas, and help determine in an unpartial way what we had to look for in the years 1982 to 1993.

And like most all the studies we have seen prepared by other people, it's a very modest increase in energy consumption and a modest increase in natural gas consumption, some showing some decline. But the growth in energy demand is met primarily through increased use of coal and nuclear energy and, as Mr. Wheeler indicated, more reliance on imported oil.

I'd call your attention to chart 1 in our testimony. Column 2 shows the rapid increase in supply that must come from new discoveries. Column 1, on the other hand, shows a very rapid runoff of old gas.

CHART I

Natural Gas Supplies Available to the Domestic Gas Utility Industry under Oil Adequacy Assumptions

(Trillion Btus)

	Lower 48 states natural gas from conventional sources			Supplemental gas							
Year	Old gas[a]	New gas[b]	Total	Liquefied natural gas	Synthetic natural gas[c]	Alaskan	North American[d]	Coal gas	New technology[e]	Total supple-mentary	Total gas
1982	8,431.7	4,365.2	12,796.9	65.0	208.0	0.0	1,000.0	11.0	0.0	1,284.0	14,080.9
1983	7,425.1	4,975.2	12,400.3	200.0	172.0	0.0	1,800.0	10.0	0.0	2,182.0	14,582.3
1984	6,499.7	5,439.4	11,939.0	200.0	136.0	0.0	2,000.0	9.0	0.0	2,345.0	14,284.0
1985	5,840.3	6,143.3	11,983.6	200.0	100.0	0.0	2,200.0	50.0	59.9	2,610.0	14,593.6
1986	5,179.0	6,999.9	12,178.9	200.0	100.0	0.0	2,300.0	60.0	109.9	2,769.9	14,948.8
1987	4,515.9	7,150.1	11,666.0	200.0	100.0	0.0	2,450.0	70.0	169.8	2,989.9	14,655.9
1988	4,033.0	7,413.1	11,446.0	200.0	100.0	0.0	2,600.0	80.0	469.8	3,449.8	14,895.8
1989	3,376.1	7,670.0	11,046.1	200.0	100.0	0.0	2,700.0	190.0	779.7	3,969.8	15,015.8
1990	2,888.6	7,855.7	10,744.4	200.0	100.0	0.0	2,800.0	300.0	1,079.7	4,479.7	15,224.1
1991	2,574.3	7,835.7	10,410.0	200.0	100.0	400.0	2,900.0	420.0	1,329.7	5,349.7	15,759.7
1992	2,267.1	7,895.2	10,162.4	200.0	100.0	900.0	3,000.0	540.0	1,579.4	6,319.4	16,481.8
1993	1,973.1	7,931.2	9,904.3	200.0	100.0	1,000.0	3,100.0	660.0	1,839.4	6,899.4	16,803.7

Note: Natural gas volumes exclude company usage and direct producer/consumer transactions.

a. Old gas represents pre-1977 flowing "Old-Old" interstate and intrastate gas.

b. New gas represents post-1976 "New-Old" (1977-81) and "New-New" (post-1981) gas.

c. Synthetic natural gas includes gas manufactured from oil feedstocks and from natural gas liquids.

d. Includes gas from Canada and Mexico.

e. Includes gas from coal seams, in situ coal gasification, peat and oil shale gasification, geopressured gas, and gas from biomass and waste conversion.

Source: TENRAC oil and gas supply model and TERA demand/marketplace model.

In addition, the remainder part of our supply is expected to come from supplementals. It's a rather uninspiring picture of gas availability, but I note that 80 percent of the new availability is going to come from the discovery of new reserves. That's the business we're in.

But as the chart demonstrates, if we are to even stay even and simply maintain our present position in the domestic fuel role, substantial exploration and development is going to be required.

I found the study encouraging for our company, but its implications for the country are a little more troubling.

CHART II

U.S. Energy Consumption by Primary Fuel Source under Oil Adequacy Assumptions

(Quadrillion Btus)

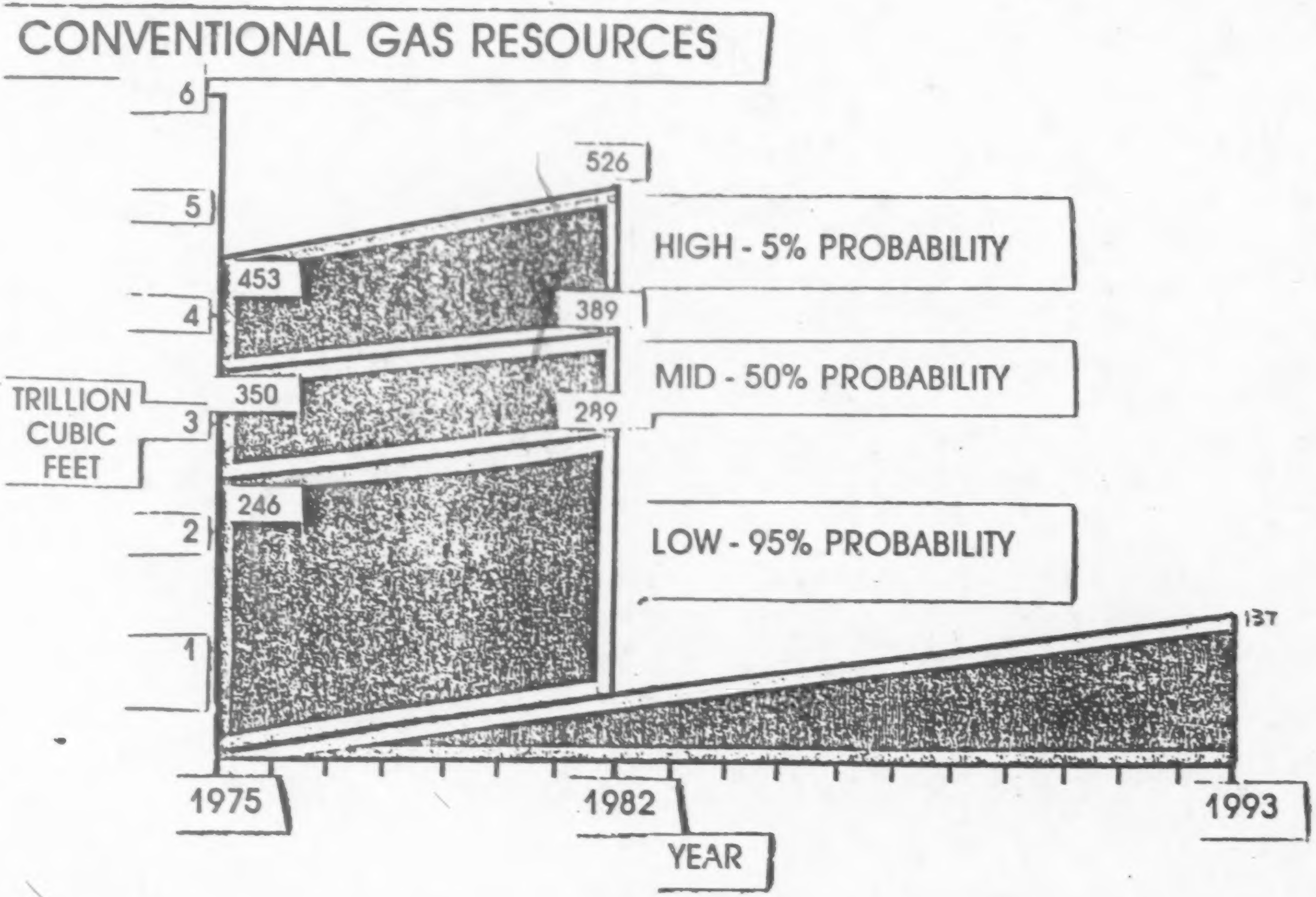
Year	Natural gas	Oil	Coal	Nuclear	Hydro	Total
1982	17.98	30.27	15.57	3.41	3.43	70.66
1983	18.45	31.51	13.91	3.51	3.42	70.80
1984	19.18	32.14	14.37	4.01	3.44	73.14
1985	19.12	32.93	14.74	4.68	3.49	74.96
1986	19.52	32.76	14.88	5.04	3.51	75.71
1987	19.88	32.86	15.63	5.54	3.58	77.49
1988	20.00	33.35	16.43	5.81	3.64	79.23
1989	20.33	33.03	17.38	5.90	3.67	80.31
1990	20.24	32.96	18.04	5.84	3.68	80.76
1991	20.35	33.17	19.21	5.76	3.73	82.22
1992	20.18	33.47	20.26	5.68	3.75	83.34
1993	20.22	33.72	21.32	5.59	3.77	84.62
Compounded annual rate of change (percent)	1.1	1.0	2.9	4.6	0.9	1.7

Source: TENRAC oil and gas supply model and TERA demand/marketplace model.

Chart 2 gives the study projections for domestic fuel consumption, and when I look at the chart I ask whether our country will realistically increase nuclear power by 60 percent over the next decade. I also ask myself whether we will want to increase our use of coal to the extent that we're projected here. And I also ask whether it's in our interest to increase foreign oil to the tune of about 1½ million barrels per day.

With the technology of gas exploration in its infancy, no econometric model can tell us how much gas we will find until we look for it. But the Nathan Study does demonstrate two plain realities: first, that to the extent we can find gas, we relieve pressure to use foreign oil, with its national security drawbacks, and coal, with its environmental drawbacks, and nuclear power, with its safety and public acceptance drawbacks; second, that if we do find quite a lot of gas, we will be faced with relying on these alternative fuels to a far greater extent than anyone would wish, or we face energy shortages.

CHART III


CONVENTIONAL GAS RESOURCES
6
5
4
3
2
1
TRILLION CUBIC FEET
453
350
246
526
389
289
HIGH - 5% PROBABILITY
MID - 50% PROBABILITY
LOW - 95% PROBABILITY
137
1975
1982
1993
YEAR

On chart 3, I tried to compare the projection of consumption in the Nathan Report with the rate of finding as measured by the USGS and the expected finding in the last years from 1975 through January 1982.

Now, it appears to me that this chart begs the question of whether or not the utilization of only 137 Tcf of gas during that period is the proper rate of gas utilization against the reserve base that we would anticipate by this study.

As to the role in Government, the new gas supplies which we need to find are going to be located in hostile environments, tough logistics, and geographically far removed, each well representing major resources and capital. An investment of this scale can be only made if businesses are able to plan on a 10-year horizon. And because the role of Federal Government is so important in our industry, we must have assurance of reasonable stability in Federal policy.

Knowledgeable observers agree that consumers and industrial users are likely to face shortages of natural gas in the next 2 years, and the recent actions of the House Energy and Commerce Committee can only accelerate and accentuate those shortages.

I believe that much of the problem is information. Change has been so rapid in the natural gas industry over the past 7 years that policymakers inevitably are operating on the basis of outdated impressions rather than current facts.

We desperately need a new national consensus on broad gas policy which reflects today's circumstances, and I am optimistic enough to believe that such a consensus can emerge from a fair-minded, impartial review of the situation.

Therefore, I have recommended the Congress suspend action on pending legislation affecting natural gas, and immediately establish a commission to examine gas policy.

For the first 6 months, I suggest that the commission examine questions that bear directly on the current legislative debate, what working assumptions should be made about the size of the resource base, can the current situation justify more intervention in gas pricing, are the legislative restraints on the end use of gas still justified.

The commission could then report to congress on these issues, which might well be taken up within this session.

Following this interim report, I would suggest that the commission examine what I believe to be the need for a pro-gas national policy.

My prepared testimony sets out a number of issues which the commission might examine. These include questions such as, what is the real cost of burning coal; how can we best use our Alaskan gas, do we wait until all the lower cost gas is exhausted, or do we find a way to blend the gas and let the price rise gradually; why wouldn't it be useful to consider a strategic gas reserve, like the strategic petroleum reserve; should we strenghten the incentives for investment of risk-capital and gas exploration?

The data that I have obtained indicates that investment in public real estate partnerships increased from $1.6 to $4.5 billion between 1981 and 1983 as a result of more favorable tax treatment afforded real estate.

In the same period, investment in public-owned gas income vehicles, programs that purchase production, increased from $786 million to $1.8 billion. Yet in those 3 years, investment in public drilling programs partnerships decreased from over $2 billion to $722 million.

Now, this is a massive capital shift away from risk, and at a time, it seems to me, that every study will agree that we need to be doing more drilling.

So I believe that an impartial examination would reach a concensus that gas is plentiful, that it can substantially reduce our dependence on fuels which are inferior environmentally; that it can play a crucial role in reducing dependence on foreign oil; and, that with stable, hospitable treatment by Government, price competition between gas and alternative fuels will greatly benefit our consumers.

Mr. Chairman, thank you.

[The prepared statement of Mr. Dyer follows:]

TESTIMONY OF JAYE F. DYER
PRESIDENT, DYCO PETROLEUM CORPORATION
BEFORE THE SUBCOMMITTEE ON ENERGY REGULATION
SENATE ENERGY COMMITTEE

Thursday, April 26, 1984

Mr. Chairman, I am Jaye F. Dyer, President and Chief Executive Officer of Dyco Petroleum Corporation. I thank you and the members of the Subcommittee on Energy Regulation for this opportunity to participate in your examination of natural gas reserves and resources in North America. I cannot resist observing that our industry and American consumers would be well served if those in the House of Representatives who are now rushing to legislate dramatic changes in natural gas policy would join this Subcommittee in first considering some inconsistencies and inaccuracies in the accepted wisdom on which these important decisions are being made.

Dyco Petroleum Corporation is principally engaged in natural gas exploration and development. We are active independent producers in the Anadarko Basin of Oklahoma, the Overthrust Belt of the Rocky Mountain states, and Alaska.

Dyco was founded in 1971 on the principle that publicly offered drilling programs can be an important source of investment for development of domestic energy resources. Our company is publicly traded. We represent approximately 7,000 shareholders, and nearly 20,000 investors who have placed over $360 million in our drilling programs. Dyco's reserves of natural gas now exceed 65 mbcf, and our reserves of oil exceed 960 mb. I believe our experience gives us in Dyco a special insight into the nature both of the natural gas resource base and of the capital markets which must support its exploration and development.

Discovering the Size of the Resource Base

I fully agree with the testimony of my colleague Erving Wolf regarding the size of the potential resource base. The forecasts by the Potential Gas Committee and the U.S. Geological Survey (USGS) suggest that our proved and remaining undiscovered reserves, assuming no advances in technology, amount to at least a fifty-year supply of gas or more at our current normal rates of use (20 tcf a year). Of the available resource base estimates, the Potential Gas Committee and USGS are almost certainly the best because they make the greatest effort to take into account the recent changes in our industry. Only in the last few years have we begun to explore for natural gas in its own right, apart from exploration for oil, and in sediments and at depths at which oil is not found.

Other estimates which rely on econometric models based on outdated data regarding oil and "associated" gas discovered as a by-product of the oil search are highly questionable. These models cannot take into account the very different characteristics of the search for non-associated gas. However, because our experience with gas is so brief, the Potential Gas Committee and USGS forecasts also are likely substantially to understate the resource base.

The fact is that we are only beginning our experience with the search for dry gas, and the data we now have which reflects that experience are fragmentary and very brief in duration. It is well to bear in mind the cautionary note placed by the Office of Technology Assessment in its recent Technical Memorandum:

> Certain technical uncertainties--primarily those associated with incomplete geological understanding, alternative interpretations of past discovery trends, and difficulties in projecting likely patterns of future gas discoveries--are so substantial that by themselves they prevent a reliable

> estimation of the remaining recoverable gas resource and the likely year 2000 production rate. U.S. Natural Gas Availability: Conventional Gas Supply Through the Year 2000, A Technical Memorandum, September 1983, p. 3

Models and forecasts are only as definitive as the data on which they are based. Therefore, while resource base studies can raise interesting questions, no model or forecast can tell us how large the resource base may be. I submit that the educated judgment of geologists and explorationists who have engaged in the gas search is at this time a far more reliable guide to the size of the potential resource base than any model. This panel is, I believe, representative of that educated judgment. Those of us in the best position to know and with the most at risk agree in our judgment that the resource base is very large.

There are sound reasons for our opinion that the existing estimates are too low. Dry gas is very different from oil and from associated gas in ways that we have not yet had the experience to quantify. Forecasts based on our experience with oil and associated gas cannot adequately reflect our prospective finding rates, quantities and recoveries. Two good illustrative examples are recovery rates and the life of gas wells.

We now can recover almost all of the gas we find, while only about a third of the oil can be recovered from a typical well. Theoretically most or all associated gas can be recovered. However, because this gas must be removed to get the oil, I would guess that as much as half the associated gas that has been found has been flared and lost both to the consuming public and to the data base.

Just as gas wells have greater recovery rates, our experience suggests that onshore gas wells have far longer lives than oil wells. I took a look at the production figures for the Hugoton gas field in Kansas and Oklahoma, which was discovered in 1926.

That field took thirty-six years, until 1962, to reach peak production. The field stayed at its peak for thirteen years before beginning a gentle decline. Today, nearly sixty years after its discovery, the Hugoton field continues to produce at around eighty-four percent (84%) of its peak. In my opinion, therefore, our current resource base estimates understate the productive lives of onshore discoveries. (This analysis does not apply to offshore gas wells, which are relatively short-lived.)

For these and other reasons, if our industry is given the freedom to produce and explore for gas, I am confident that we will prove these forecasts to be substantially understated and that we will develop the new technologies to further expand the base of potentially discoverable gas.

Dyco's Perspective

When Dyco was established at the beginning of the 1970s, gas was commonly viewed as a by-product of oil, the resource base was believed to be near exhaustion, and public regulatory policy discouraged investment in gas exploration and development. Nevertheless, like other independent companies represented here today, we decided to concentrate on natural gas.

We knew that, despite conventional wisdom, the resource base had hardly been tapped. We knew that domestic natural gas is better than foreign oil from the point of view of national security, better than coal environmentally, and better than nuclear power in terms of risk and public acceptance. And we believed that because gas is so attractive, the price of gas would eventually be allowed to rise toward parity with oil, establishing an adequate incentive for exploration and production.

In the decade that followed, we did see gas prices rise toward those of oil, we did find gas, and together independent producers proved the pessimists wrong about the size of the available resource. We have never regretted our decision to be in the gas business. Our disappointment is that general opinion and public policymakers still do not fully recognize the enormous advantages of gas in comparison to other fuels, and the contributions gas can make to the quality of life in this country for the remainder of this century and beyond.

As we entered the 1980s and Dyco's second decade, we wanted to review the prospects for the future of our industry. To help with that review, we requested an econometric study by Robert R. Nathan and Associates of markets for natural gas and competing fuels between 1982 and 1993.

The study uses the Texas Energy and Natural Resource Advisory Council's (TENRAC) oil and gas supply model and the American Gas Association's (AGA) Total Energy Resource Analysis (TERA) demand/marketplace model. Like any analysis based on an econometric model, the Nathan Study cannot accurately predict the availability of natural gas. However, because the methodology let us look at gas in relation to alternative fuels, the Nathan Study raises the right questions. Although in my view the methodology used substantially understates the potential performance of gas from conventional sources, we have found the report very useful in our planning.

Like many of the studies with which you are familiar, the Nathan report forecasts moderate increases in U.S. energy consumption over the next decade (1.7%/year), and natural gas consumption stabilizing at roughly 20 tcf/year. Growth in energy demand is met primarily through increased use of coal and nuclear energy, and additional reliance on imported oil.

I call your attention to Chart I, which is attached to my testimony. Column 2 shows the rapid decline in supplies from old gas, with 1993 availabilities reduced by more than seventy-five percent (75%) from 1982 levels. This certainly reflects realities. Columns 5-11 set forth very ambitious projections for supplemental gas, which I believe may prove difficult to achieve. Overall, the chart and the Nathan Study project very modest increases in gas availability and a decline in availability of gas from conventional sources in the Lower 48 states. Nevertheless, this uninspiring picture of gas availability is made possible only by an increase of over eighty percent (80%) in new gas availability. This chart is encouraging to us from a corporate point of view, because it demonstrates that even if natural gas is simply to maintain its present role as a domestic fuel, substantial exploration and development of our natural gas resource base will be needed.

Although I found the study encouraging for Dyco, its implications for our country are troubling. Chart II gives the study's projections for domestic fuel consumption.

When I look at this chart, I ask whether our country will realistically increase nuclear power consumption by sixty percent (60%) over the next decade?

I ask myself whether we want to or will increase our use of coal by six quads or 270 million tons per year, with all the environmental damage this will cause, or alternatively with the huge expenditures on mitigation which would be required?

I ask whether this is the time for us to be increasing our dependence on foreign oil to the tune of about 1.5 mmb/day? I know of no new development which makes the Middle East a more reliable source on which to depend. In fact, I am sure this Committee would agree that our national interest lies in reducing this dependence.

With the technology of gas exploration in its infancy, no econometric model can tell us how much gas we will find until we look for it. But the Nathan Study does what a study can do. It shows us what the questions are. The study demonstrates two plain realities:

> First, that to the extent we can find gas, we relieve pressure to use foreign oil with its national security drawbacks, and coal with its environmental drawbacks, and nuclear power with its safety and public acceptance drawbacks.
>
> Second, that if we do not find quite a lot of gas within the next decade, we will be faced with relying on these alternative fuels to a far greater extent than anyone would wish, or facing real energy shortages.

The Nathan Study is encouraging to gas producers because it shows our commodity will be needed. I hope it sends the same message to policymakers.

I would now call your attention to Chart III. This chart compares the projections of the Nathan Study with the conventional gas resource estimates of the USGS for 1975 and 1982. This chart does not prove anything, any more than an econometric study does. But it does suggest that when our industry is allowed to search for gas, we find it in quantities larger than others predict. I believe that if we are allowed to look for the substantial increased supplies that we need just to continue meeting our existing demand, we will find enough more for natural gas to play a greatly expanded role, with all the attendant benefits in terms of environmental quality and national security.

The Role of Government

Government cannot escape responsibility for the behavior of natural gas markets because its influence is so pervasive. Even if natural gas is deregulated at the wellhead as it should be, the pipelines and distribution companies, who are the first and second purchasers of our commodity, are and will continue to be subject to intensive federal and state regulation. In addition, federal tax policies have an important impact on our industry's ability to raise risk capital.

The new gas supplies which we must find are located in environments logistically, geologically and geographically far more hostile than those in which oil and gas exploration has taken place in the past. Each well represents a major investment of resources, expertise and capital. Investments of this scale can be made only if businesses are able to plan on a ten-year horizon. And because the role of the federal government is so important in our industry, we must have assurance of reasonable stability in federal policy. We clearly do not have that assurance today.

Right now the majority of the House Energy Committee are fighting the wrong war. Constituents see a surplus of deliverability, and remember stories of $9 gas. In response, producers are threatened with reimposition of price controls, and pipelines are jawboned not to sign long-term contracts for new gas production. Pipelines and producers did make mistakes with the new freedom they were given by the Natural Gas Policy Act of 1977 (NGPA). But our industry has paid a high price, and we have learned the lesson of $9 gas.

Today there is no more high-priced gas, and as others have testified the "gas bubble" is all but gone. Just when a free market would let our depressed industry go back to work to prevent the looming shortage, government threatens to stop us. And I can tell you that it does not take enactment of laws or new rulings by regulators to stop exploration and production. Just the threat of these actions has a strong adverse impact on our ability to raise investment capital. Knowledgeable observers agree that consumers and industrial users are likely to face shortages of natural gas in the next two years, and the actions of the House Committee can only accelerate and accentuate those shortages.

I believe that much of the problem is information. Change has been so rapid in the natural gas industry over the past seven years that policymakers inevitably are operating on the basis of outdated impressions rather than current facts. We desperately need a new national consensus on broad gas policy which reflects today's circumstances. And, I am optimistic enough to believe that such a consensus can emerge from a fair-minded, impartial review of the situation.

The future of natural gas is an issue every bit as important to our country as the issue of Social Security. And it should be even more susceptible to solution because, at least in my view, achieving adequate supplies of natural gas should not require sacrifices by any part of our population. I recommend that Congress suspend action on pending legislation affecting natural gas, and immediately establish a blue-ribbon commission to examine gas policy.

For the first six months, I suggest that the commission examine questions that bear directly on the current legislative debate. These include:

° How large is the resource base? We will never learn except by exploring. But I believe an impartial examination would lead to the conclusion that it is wise to let our industry bet on its expansive view, both because the optimists have been right so far and because it is so important for our country for them to be proven right.

° Can the current situation justify more government intervention into gas pricing and contractual relations between producers and pipelines? In my view, the problems are sorting themselves out, additional intervention would be counterproductive, and even the perceived advantages of intervention are outweighed by the harm of setting a precedent which would be difficult not to repeat.

° Are legislative restraints on the end-uses of gas (incremental pricing and Fuel Use Act) still justifiable? In my view, these restraints are the clearest possible example of policies based on outdated impressions of our industry.

The commission could report to Congress on these issues, at least preliminarily, in time for legislative action in this Congressional session.

Following this interim report, I would suggest that the commission examine what I believe to be the need for a "pro-gas" national policy. For example:

° If the resource base is as large as 500 tcf or bigger, how should we be using it?

° What is the real cost of burning coal and oil, taking into account the full range of public and private costs? Does this suggest the need for some change in public policy so that the relative price of gas reflects its real value and consumers and industrial users are given incentives to switch from coal and oil to gas?

° Why wouldn't it be useful to establish a Strategic Gas Reserve, like the Strategic Petroleum Reserve, which would be available to provide relief to consumers and industrial users in times of inadequate deliverability. Reports from the Texas Railroad Commission indicate that last December we were on the verge of deliverability shorages. Mismatches of supply and demand and resulting shortages could be prevented by establishing a Strategic Gas Reserve.

° How can we best use our Alaskan gas? Do we wait until all the lower cost gas is exhausted, or do we find a way to blend the gas and let the price rise gradually? Do we build a transportation system soon, or do we wait until demand is overwhelming? (We delayed the oil pipeline until the word was "get it done at any cost"--and that is what it cost.) In the interim, do we allow export of Alaskan gas, thereby maintaining the exploration incentive, or do we risk not determining the size of the resource until the need for it is upon us?

We have been lucky that the geology of Prudhoe Bay has permitted reinjection of that gas, at least so far. There is no guarantee that we will be so fortunate with the next discovery. As long as there is no pipeline to the Lower 48 states and the legislative ban on exports continues, I believe the rate of exploration on the North Slope will be governed by the ratio of gas to oil found. If the North Slope gets a reputation for being "gas prone" then exploration will stop. I believe that construction of the ANG pipeline should be expedited and that in the interim export of the gas should be allowed.

° Should we strengthen the incentives for investment of risk capital in gas exploration? For many years investments in oil and gas exploration received favored treatment under the federal tax code; with enactment of ACRS accelerated depreciation and other recent amendments, this relative advantage vanished. Drilling for gas is more difficult and capital intensive than ever before. Yet the tax system now shifts capital away from risk.

Data I have obtained from Robert W. Stanger indicates that investment in public real estate partnerships increased from $1.6 to $4.5 billion between 1981 and 1983. In the same period, data I have obtained from Investment Search, Inc. indicates that investment in public oil and gas income vehicles increased from $786 million to $1.8 billion. Yet according to the Investment Search data, in those three years investment in public drilling partnerships decreased from over $2 billion to $722 million. This massive capital shift away from risk should be a matter for national concern.

° Shouldn't we step up our federal research and development for gas technology? Why is $15 billion being spent through the Synthetic Fuels Corporation on expensive coal and shale technologies, which are likely to be "white elephants", while natural gas is ignored? Why should the Electric Power Research Institute (EPRI) be allowed to have a budget several times larger than the Gas Research Institute, and why shouldn't the Energy Department's program be more balanced?

I believe that an impartial examination would reach a consensus--that gas is plentiful, that it can substantially reduce our dependence on fuels which are inferior environmentally, that it can play a crucial role in reducing dependence on foreign oil, and that with stable, hospitable treatment by government, price competition between gas and alternate fuels will greatly benefit consumers.

Mr. Chairman, thank you for the leadership you have displayed in calling this hearing. I hope it can begin the process of creating a new partnership between national policymakers and our industry in the interest of expanded gas supplies at competitive prices--to the great benefit of our environment, our national security, and our domestic economy.

Senator MURKOWSKI. Thank you very much, Mr. Dyer.

You brought up some rather interesting proposals. The concept of the strategic gas reserve has been contemplated from time to time, and perhaps it's due for another examination. I really don't know.

One thing. You indicated in your opening remarks that you were engaged as a corporation primarily in natural gas exploration and development. Why would you want to go to Alaska for gas when you can't get a return on your investment? You would go to the North Slope now, I make that assumption.

Mr. DYER. Our targets in Alaska are not natural gas. We may wind up——

Senator MURKOWSKI. You're not interested in going to Alaska to look for natural gas.

Mr. DYER. Well, our primary hope would be oil.

Senator MURKOWSKI. I see.

Mr. DYER. But we may wind up with natural gas.

Senator MURKOWSKI. What are you going to do with the gas if you find it?

Mr. DYER. The exploration efforts that we're involved in, our first and most immediate concern is finding something.

Senator MURKOWSKI. Finding something.

Mr. DYER. Right.

Senator MURKOWSKI. You're going hunting for oil, and you might find gas; and, if you find gas, you're going to hunt for some more oil?

Mr. DYER. You know, it's not unusual in our industry—the Alaskan situation is too disimilar to what it was in the panhandle of Texas in 1959. There we did much exploration, invested a lot of money developing dry gas. And what we had to do was to show enough reserve to justify a pipeline.

So being in the natural gas business, one of the hazards is that the finding has to come first, there's a waiting period, and the pipelines come sooner or later.

Senator MURKOWSKI. Do you think 32 Tcf are enough to justify a pipeline so that Alaska gas can be marketed through one proposal or scheme or the other?

Mr. DYER. I'm not qualified to say how much is. I know this, my concern about Alaskan gas is simply that at some point in some emergency we might need the oil so bad that we would have no alternative but to flare the gas. That would be my principal concern.

That's my feeling, and that long-term planning needs to be done to bring that pipeline in as soon as possible; if for no other reason, a part of a strategic gas reserve.

Senator MURKOWSKI. And if that pipeline were to be built, it would be built, I assume, as a common carrier. So you would be able to market any gas that you might find as an independent operating in an area where major oil companies hold substantial gas reserves. I assume it would be understood that that pipeline would be a common carrier.

Mr. DYER. Well, even on that score, I'm not prepared to say. I know one way we——

Senator MURKOWSKI. Well, how would you get your gas out if it wasn't a common——

Mr. **Dyer**. We'd be fist-fighting trying.

Senator **Murkowski**. Oh, I see.

Having had the opportunity to reflect, there's one other question I wanted to ask Mr. Wheeler.

I've got a map before me that says the Alaskan Natural Gas Transportation System, and on it just below Prudhoe Bay at Anchorage is the Dempster Lateral, which is proposed to go into White House.

My question is an obvious one, I'm sure, Mr. Wheeler, but it would appear less costly to bring Canadian gas down first and then you wouldn't have to build that 800 miles or so of pipeline in Alaska. Is that a reasonable assumption, or is it fraught with generalities?

Mr. **Wheeler**. Well, I'm not an expert on—I come as a geologist to talk about our forecast of reserves, not about the economics of moving gas from Alaska, Senator. But I'm not sure that if one were setting out to build a supply line from Canada alone that one would look to the Dempster Lateral at all, but wouldn't chose a different route.

Senator **Murkowski**. Well, we had better send this map back to the drawers and get the different route in here.

I thank you. That was a bit of a curved question, but you handled it very well.

Mr. Ervin Wolf, chairman of the board, and president of Inecho——

Mr. **Wolf**. In-ex-co, Inexco.

Senator **Murkowski**. Inexco.

Mr. **Wolf**. Repeat after me. [Laughter.]

Senator **Murkowski**. Inexco.

Please proceed, Mr. Wolf. We appreciate your participation and look forward to your brilliant testimony which is about to begin.

STATEMENT OF ERVING WOLF, CHAIRMAN AND CHIEF EXECUTIVE OFFICER, INEXCO OIL CO.

Mr. **Wolf**. I am chairman and chief executive officer of Inexco Oil Co. which is headquartered in Houston.

We are one of the larger independent exploration companies. We're listed on the New York Stock Exchange, and we have approximately 340 Bcf of gas reserves as of December 31, and it's all domestic onshore.

This is part of our business, along with looking for oil and gas, and we also have a drilling company.

The preceding panel provided a range of gas resource base estimates. I'm an independent explorer for natural gas who cannot competently discuss the mythology of these estimates.

What I can testify to is my own experience, which demonstrates that when you drill in good geological areas, with competent staff, the more you drill the more you find.

As such, it is clear to me that:

First. Estimates which are more closely based on actual experience are more valid than hypothetical assumptions based on oil exploration.

Second. Any estimate based on today's technology and economics has got to be too low.

Inexco has firsthand reason to be optimistic about the future. We've increased our reserves over production by a 2-to-1 ratio over the past 6 years, despite reducing our budget in 1983 and 1984. The reason for this is clear, we drill in good areas, using the best available technology.

In the areas in which we have had direct experience, the estimates of remaining undiscovered supplies have steadily climbed. For example, since 1970, the Potential Gas Committee's estimate of the share of the Nation's remaining gas resources in the mid-continent and north region is up almost 50 percent. The estimated share in the Rocky Mountain region is up fivefold, and the estimated share beneath 15,000 feet has doubled.

The estimated amount of remaining undiscovered gas in these provinces is up significantly, despite the fact that tens of trillions of cubic feet have been converted from potential to proved reserves during this period.

As both the economics and technologies for extraction of natural gas improve, there is every prospect that the amount of remaining resources which are economic to develop will remain constant at about 900,000 to a thousand Tcf, and perhaps expand.

In other words, our firsthand experience shows that the more we drill in good prospects the more we find, and the more we learn from actual drilling, the more we know. And as exploration intensifies and moves toward deeper sediments, our previous estimates have been understated.

Yet despite the abundance of the resource base, the near-term supply outlook looks grim. The main problem is the perception of massive excess deliverabilities that no longer exist. This is stifling exploration.

Drilling, and particularly exploration drilling is way down.

Most pipelines and many policymakers have come to see the dangers posed by these excess deliverabilities, but that was yesterday's problem. Today, actual market conditions have changed. We in Inexco disagree vehemently with those who are that there's a gas bubble of 3, 4, or even 7 Tcf of gas. Natural gas at this moment are closely balanced with demand.

In 1982 and 1983, our country experienced several extraordinary circumstances which combined to produce a sharp drop in natural gas use: First, the worst recession in 50 years; second, milder than normal temperatures, and; third, heavy rainfall and heavy snow cover in the Pacific Northwest, which made available the equivalent of three-quarters of a trillion cubic feet of gas in hydropower for use in place of natural gas.

Similarly, on the supply side, a Texas Railroad Commission Study found, despite reports of producers a potential deliverability of 24 Bcf per day, that Texas gas wells were actually capable of delivering only about 14 Bcf per day during the cold snap last December.

Merrill Lynch's energy economists estimate that deliverability actuall peaked in 1982 and, contrary to popular belief, decined in 1983 from 22 to 21 Tcf.

Moreover, Merrill Lynch projects that deliverability will continue to decline to 19.7 Tcf in 1984, 18.8 Tcf in 1985, and 17.8 Tcf in 1986.

Mr. Chairman, the natural gas bubble has broken. The excess deliverability of 1982 and 1983 is gone. It would be a tragedy for our nation if a mistaken belief in the natural gas bubble which no longer exists were to drive our country into a period of shortages and much higher prices, prices far beyond those necessary, given the abundance of America's natural gas resource base.

And knowing that drilling has already fallen sharply, and knowing the economy's rebounding, and knowing that we cannot forever expect abnormally warm winters, and knowing that supplies are certain to contract in the near term while demand grows, current action by the House of Representatives to pass the recontrol bill by the Energy and Commerce Committee would be not only unwise, it would be irresponsible.

This legislation would drive our nation into a supply crisis far worse than the 1970's, because unlike the situation then, there will be no intrastate gas surplus to ease shortages in consuming states.

It's as though the House Committee was in cahoots with OPEC.

Senator MURKOWSKI. Well, I'm glad you gentlemen brought that up. Now, it's on the record. It'll be over in the House this afternoon.

Mr. WOLF. OK. The name is Inexco, I-n-e-x-c-o. [Laughter.]

Senator MURKOWSKI. OK.

Mr. WOLF. Due to the potential loss of cash flow to the exploration business that could be caused by the passage of the House bill, we will see 12,000 to 15,000 thousand less gas wells drilled in this country between the years 1985 and 1990, which is tantamount to shutting down all natural gas drilling in the United States for 12 to 18 months.

Mr. Chairman, there are several things that Congress could do to enable our country to realize the enormous potential of our domestic natural gas resources: First, direct the appropriate authorities to fully investigate and dispell the myth of the bubble; second, billions of tax dollars have been spent in the name of energy independence, an essential national goal. In the future, a pro-domestic gas policy will save billions of future dollars for the consumers through national decision to develop to the fullest our abundant natural gas resource base; third, continue the drive toward free market pricing of natural gas by honoring the commitments made to producers in the Natural Gas Policy Act; fourth, open up the market to natural gas, let users decide which fuel is best, without artificial government and end-use restraints; fifth, don't wreak havoc on our industry through recontrol legislation.

This House committee bill I refer to which recontrols prices and abrogates contracts will create shortages by severely reducing the cash flow to independent exploration companies; thereby, preventing the development of new gas supplies.

I earnestly hope that your colleagues in the House will carefully consider the issues raised during these hearings today before proceeding toward enactment of lesiglation which will create severe costly, and totally unnecessary natural gas shortages.

I thank you very much.

[The prepared statement of Mr. Wolf follows:]

STATEMENT OF ERVING WOLF, CHAIRMAN

INEXCO OIL COMPANY

INTRODUCTION

Mr. Chairman, my name is Erving Wolf. I am Chairman and Chief Executive Officer of Inexco Oil Company, headquartered in Houston, Texas. On behalf of Inexco, I would like to express our appreciation for this opportunity to meet with you today to discuss our nation's natural gas resource base and the means by which this resource base can be converted into reliable, abundant, and reasonably priced energy reserves to serve American consumers.

Inexco Oil Company was founded in 1968. While we are a relatively new company, Inexco has grown rapidly. In 1983, we were ranked by Oil Daily as the 33rd largest independent oil and gas producer in the United States. Inexco has developed more gas reserves than a number of well-known companies, such as Adobe, Apache, Noble, Pogo, Sabine, Lear, Woods and others. Inexco has active drilling programs underway at the present time in Louisiana, Texas, Oklahoma, Alabama, Mississippi, Wyoming, New Mexico, and North Dakota. We have undeveloped acreage for future drilling in every producing state west of the Mississippi River.

Like many independents, Inexco began as an oil company. Our initial exploration efforts were centered on the search for petroleum in the Rocky Mountain states. But in the early 1970's, Inexco's corporate strategy changed. It became obvious to us that there was less and less potential for signficiant new petroleum liquids discoveries in the onshore producing regions of the lower 48 states. At the same time it became more and more apparent that there was great potential for major new discoveries of natural gas.

Inexco began to move toward deeper natural gas drilling in the mid-1970's, well before incentive prices were enacted as part of the Natural Gas Policy Act (NGPA). We moved toward deeper drilling not because of federal price incentives but instead because it is in the deeper sediments that the nation's largest -- phenomonally large -- remaining reserves of natural gas are found.

Mr. Chairman, you may have read the recent articles about the major new gas find, located thousands of feet beneath the first gas field ever discovered in the State of California. Based on Inexco's own experience, the same is true in virtually all of the major producing provinces in the United States. In Evangeline Parish, Louisiana, we drilled beneath the Reddell field, a shallow field developed in the 1950's and 1960's and discovered one of the biggest gas reserves in that state. Similarly, in Wyoming, we drilled below the Madden field and found significant new reserves of natural gas. Some geologists believe vast undiscovered gas resources lie beneath the Hugoton field in Kansas and Oklahoma and beneath dozens of other major producing provinces.

We are proud of Inexco's success as an exploration company. Between 1979 and 1983, our company's natural gas reserves rose by 50 percent. Last year, for every cubic foot of gas produced by Inexco, over two cubic feet in new reserves were found. In the first quarter of 1984 alone, we have again increased Inexco's reserves significantly, through the discovery of what may prove to be one of the largest fields ever found in the State of Alabama.

THE NATURAL GAS RESOURCE BASE

The panel which just appeared before you has provided you with a range of estimates concerning the natural gas resource base. I have the greatest respect for the professional qualifications of those witnesses. However, the only thing that is certain about all of the estimates is that they are wrong. The U.S. Geological Survey in 1946, made the following statement concerning gas resource base estimation, "Information is not available that will permit an estimation of the magnitude of our future discoveries of natural gas in exact terms, either cubic feet or year's supply."[1] Today, as in 1946, it is impossible to quantify precisely resources which are, by definition, unknown.

Nonetheless, there is much to be encouraged about in the most recent projections of our country's remaining undiscovered natural gas resources. The Potential Gas Committee (PGC), headquartered at the Colorado School of Mines, has by far the best track record for the consistency, accuracy and underlying conservatism of its resource base estimates. PGC's most recent (1982) projection of remaining undiscovered natural gas resources, when combined with already proved reserves, suggests that our nation possesses at least a 50-year supply of natural gas at normal rates of use (20 Tcf/year).[2] This estimate assumes today's technologies and today's price incentives. It is certain that there will be substantial improvement in both the economics and technologies for extraction of unconventional and high-cost natural gas over the next half century. Thus, there is every prospect that, even as more and more gas is discovered and produced, the amount of remaining resources which are economic to develop will remain constant, and could expand dramatically in the 21st century with technologies to extract methane from tight sands and geopressurized brine.

What I find signficant about the range of resource base estimates presented over the last five years is that those which tend to be most optimistic (PGC, USGS) are the estimates which rely most directly on experience with natural gas exploration.[3] In contrast, those estimates which are most pessimistic (Rand, Hubbert) are those which rely most heavily on the history of oil exploration.[4] In other words, Mr. Chairman, the more the estimators know about natural gas, the greater the estimate of the nation's potential gas supply. Conversely, the more the estimators seek to impose judgments based on the history of oil, the more pessimistic the estimate of the nation's future gas supply. Thus, Richard Nehring of the Rand Corporation and M. King Hubbert -- estimators who rely heavily on oil-dominated historical trends -- have offered estimates so low as to be considered to lack any credibility whatsoever by the Office of Technology Assessment.[5] At the same time, the U. S. Geological Survey and the Potential Gas Committee -- which use geological data from natural gas exploration activity and incorporate the experience of teams of geologists with knowledge of gas exploration trends -- offer the most affirmative estimates of the nation's potential natural gas supply. It is no accident that oil-related data and experts disagree with natural gas-related data and experts. The heyday for oil exploration occurred in the mid-1950's. The heyday for natural gas exploration is yet to come.

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[1] U.S. Geological Survey, Circular 14, 1946. P. 20.

[2] Potential Gas Committee, Potential Supply of Natural Gas in the United States (as of December 3, 1982). June 1983. P. 5.

To the extent natural gas resource base estimates are valid, it is because they are centered exclusively on the natural gas experience. Moreover, the wellspring of data related to the natural gas experience lies in the independent producing sector, which accounts for over eighty percent of all of the exploratory drilling for natural gas underway in the United States today.[6]

Mr. Chairman, it is independent exploration and production companies who are leading our nation toward an era of energy security by developing the full potential of our country's domestic natural gas. Earlier in my statement, I mentioned the corporate decision made by Inexco to target our drilling efforts away from oil and toward natural gas. In 1983, Oil Daily reported that fully 70% of the 100 largest independent producing companies had annual deliveries of natural gas in excess of their annual production of petroleum liquids.[7] These are becoming gas companies with some oil production, rather than oil companies with some gas production. In contrast, not one of the major energy companies produced more gas than oil in 1982.[8]

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[3] Office of Technology Assessment, U.S. Natural Gas Availability. September 1983. P. 29-65.

[4] Ibid.

[5] Ibid. For a critique of the Hubbert analysis see pages 44-46, and 50.

[6] Myers, Energy Daily, May 11, 1982. P. 2.

This phenomenon is important for two reasons. First, it demonstrates that the onshore United States -- where independent producers have the financial resources and the lease positions to play -- has become much more attractive and much more successful as a natural gas, than as an oil, province. Second, it highlights the potential for more agressive future competition between gas and oil, with gas commanding immense advantages for consumers in that it is more abundant, controlled by a much larger and more diverse array of production companies, and free from the economic and foreign policy perils associated with dependence on oil imports. When you hear pessimistic assessments regarding future gas supplies from oil companies, such as that prepared by Shell in 1977,[9] be mindful of the fact that the major companies are concerned first and foremost with discovering, developing and marketing their reserves of oil.

Inexco has first-hand reason to be optimistic about the future natural gas resource base. In the provinces in which we have had the greatest drilling experience, the estimates of how much gas remains out there, waiting to be found, have steadily climbed. For example, since 1970, the PGC's estimate of the share of the nation's remaining gas resources projected to be located in the Midcontinent (North) region is up almost 50 percent.[10] The estimate of the share of America's remaining gas resources to be found in the Rocky Mountain region is up five-fold since 1970.[11] And the estimate of the share of America's remaining gas resources projected to be beneath 15,000 feet has doubled since 1970.[12] In each case the absolute amount of gas estimated to be remaining to be found in these provinces is up significantly, despite the fact that tens of trillions of cubic feet have moved from the category of potential to proved reserves during this period.

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[7] Resource Dynamics International, Oil Daily, July 11, 1983. P. B-9,10.

[8] Ibid. P. B-16,17.

[9] Office of Technology Assessment, Op. Cit., P. 5.

[10] See Potential Gas Committee, Potential Supply of Natural Gas in the United States (As of December 31, 1970), October 1971. See also Potential Gas Committee, Potential Supply of Natural Gas in the United States (As of December 3, 1982). June 1983.

[11] Ibid.

[12] Ibid.

CONVERTING RESOURCES INTO RESERVES

Apart from geology, resource base estimators typically take into account two additional factors to determine that portion of the resource base which is considered to be recoverable -- technology and economics, or price. Often, other factors, more fluid and less tangible, are at least as important as price to those who make the investments necessary to convert resources into reserves.

First, it is essential to consider trends in drilling costs. Resource base pessimists are already seizing upon the recent reduction in prices paid for high cost gas to discount the feasibility of developing a significant share of the nation's deep and tight gas resources. Certainly prices have fallen. But drilling costs have fallen too. Data from our own drilling subsidiary, shows that the daily rates for drilling rigs -- paralleling the surge in unregulated gas prices -- rose from $5,000 per day in 1979 to $10,000 to $11,000 per day in 1981. In 1983, paralleling the drop in wellhead prices, daily rates plummeted to less than $4,000. They stand at between $4,000 and $5,000 today.[13] Similarly the prices paid for tubular goods and various oil field services have fallen sharply. Lease costs in many areas have also declined.[14]

Second, and perhaps most important, but also difficult, if not impossible, for analysts to measure, are the expectations in the minds of producers and investors regarding future market conditions and the future regulatory environment.

Mr. Chairman, for the remainder of this century, I submit that it will be the expectation of potential returns -- not the size of the resource base -- that will be the central determinant of America's available gas supply. Moreover, unless they are changed, the expectations now in the minds who those who must cooperate to permit development of our country's gas resources, that is, legislators as well as lenders, gas buyers and producers, could lead our country into a major supply disaster.

THE MYTH OF THE NATURAL GAS BUBBLE

New gas independents have consistently been on target in the market predictions we have presented to this committee. You will recall in 1981 and in 1982, many voices argued that our country was destined to suffer a variety of problems because natural gas allegedly would remain underpriced in relation to oil. You were warned of impending shortages -- perhaps before 1985 -- of the potential that intrastate buyers would be unable to compete for new gas supplies, and many other problems that have simply not materialized. In contrast, spokesmen for the new gas industry said the real danger was that excess deliverabilities were rising too fast. The problem was not lack of supply but lack of demand.[15]

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[13] Estimates supplied by Inexco Oil Company.

[14] Merrill Lynch, Natural Gas Monthly, December 1982. P. 2.

Today, most pipelines and many policy-makers have come to see the dangers posed by excess deliverabilities. The only problem is that this recognition has come too late. Actual market conditions have changed. We at Inexco disagree vehemently with those who argue that there is, as we meet, a gas bubble of 3 or 4 or up to 7 Tcf.[16] There is no bubble at all. While localized circumstances will vary from pipeline to pipeline, on a nationwide basis, natural gas supplies at this moment are closely balanced with demand.

Consider the facts. With respect to demand, in 1982 and 1983 our country experienced several extraordinary circumstances, which combined to produce a sharp drop in natural gas use. The first was economic, in the form of the worst recession in 50 years. This recession severely dampened industrial, commercial and electric utility demand. The second and third were weather-related. Unusually mild temperatures reduced residential demand, lowering home heating needs in the winter, and lowering air conditioning needs in the summer. At the same time, heavy rainfall on the West Coast and dense snow cover in the Pacific Northwest made available the equivalent of three-quarters of a trillion cubic feet in hydropower for use in place of natural gas.[17]

Similarly, on the supply side, there is cause for concern. Consider the results of a study prepared by the staff of the Texas Railroad Commission (TRC). This study found that the nation's largest producing state lacked the supplies to fully meet demand during last December's cold snap. Despite reports from producers of potential deliverability of 24 Bcf per day, when the cold weather hit, Texas wells were actually capable of delivering only about 14 Bcf per day.[18] Merrill Lynch's energy analysts have begun to compile evidence that presently shut in gas wells may be unable to attain the same level of production that they were capable of attaining before they were shut in.[19] This analysis is based on the potential damage caused by a rapid increase in production rates, such as that which occured last December. The result of sharp fluctuations in production levels is an acceleration of the "breaking point" of the well, the point at which potential deliverability begins to fall.

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[15] See testimony of Robert A. Hefner, III, Before the Committee on Energy and Natural Resources, United States Senate, November 6, 1981.

[16] Estimates Reported by American Gas Association, Gas Energy Review, Vol. 12. No. 2, February 1984.

[17] Merrill Lynch, Natural Gas Monthly, March 1984, P. 5.

For all of these reasons, Merrill Lynch estimates that deliverability actually peaked in 1982, and -- contrary to popular belief -- declined in 1983 -- from 22 to 21 Tcf. Moreover, Merrill Lynch projects that deliverabilty will continue to decline to 19.7 Tcf in 1984, to 18.8 Tcf in 1985, and to 17.8 Tcf in 1986. They conclude:

> "Combining our various projections we believe that supply and demand could come into balance in the first quarter of 1985, followed by shortages in 1986 and 1987. A record cold first quarter and unseasonably cold November and December 1984, could result in a supply and demand balance in the fourth quarter of 1984."[20]

Mr. Chairman, what these facts mean is this: the natural gas bubble has burst. The excess deliverability of 1982 and 1983 is gone. Yet much of the industry and most national policy-makers continue to make decisions as though available supplies will be in surplus throughout the decade. The truth is just the reverse.

The perception of enormous excess deliverabilities has prompted a dramatic reduction in drilling activity. Natural gas well completions in 1983 totaled just over 15,000, down nearly 20 percent from 1982.[21] A more important indicator, footage drilled, plummeted from 107 million to 80 million feet in this period.[22] Reserve additions for 1983 are estimated at 10 to 12 Tcf -- just over half of annual use.

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[18] Ibid.

[19] Merrill Lynch, Natural Gas Industry Outlook for 1984. February 19814. P. 8,9.

[20] Merrill Lynch, Natural Gas Monthly, March 1984, P. 13.

[21] Energy Information Administration, Monthly Energy Review, December 1983[4]. P. 63. (DOE/EIA - 0035 (83/12[4])).

[22] American Petroleum Institute, Quarterly Review of Drilling Statistics, Annual Summary 1983. February 1984.

And, as bad as 1983 was for natural gas drilling, 1984 has started out even worse. For the first three months of this year, the number of exploratory gas well completions was down more than 10 percent compared with 1983.[23] New field wildcats fell from 145 during the first quarter of 1983 to 91 during the first quarter of 1984. The wells that were drilled were drilled to about a 10% shallower depth.[24] The rig count fell in all but one of the first thirteen weeks.

Mr. Chairman, it would be a tragedy for our nation if a mistaken belief in a natural gas bubble which no longer exists were to drive our country into a period of shortages and much higher prices -- prices far beyond what is necessary given the abundance of America's natural gas resource base.

MANDATING SHORTAGES

Given the recent downward trend in drilling, natural gas markets will inevitably tighten during the mid-1980's even without a change in policy. Knowing that drilling has fallen precipitously, knowing that the economy is rebounding, knowing that we cannot forever expect abnormally warm winters, and knowing that gas markets are certain to undergo a contraction in supply and at the same time an expansion of demand, action by the House of Representatives to pass the recontrol bill reported by the Energy and Commerce Committee would be not only unwise -- it would be irresponsible. This legislation would drive our nation into a supply crisis far worse than the 1970's, because, unlike the situation then, there will be no intrastate gas surplus to ease shortages in consuming states.

The House committee bill measure would break faith with the commitment made by the Congress in 1978 to full decontrol of high cost gas. Contracts would be abrogated. Independent producers, lacking the economic leverage and legal resources of the major companies and the pipelines, would be forced to undergo a complex, burdensome, unpredictable and costly process of federal binding arbitration. Controls on wells drilled since 1978 would be extended for an additional two years. Contracts would be breached and prices would again be determined not by the market but by the decisions of federal arbitrators. Pipelines would be directed to pay the lowest possible price for natual gas supplies, even to the extent of jeopardizing long-term reserves to serve their customers. It has been estimated that this legislation would cost our country anywhere from 12,000 to 23,000 gas wells during the period 1985-1990 -- the equivalent of shutting down all natural gas drilling in the United States for twelve to eighteen months.[25]

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[23] _Ibid_.

[24] _Ibid_.

The result of the House committee bill would be to destroy both the cash flow and the ability of producers to borrow or to attract investors to finance new drilling. Take Inexco as an example. Last year and this, our company will commit in excess of 100 percent of cash flow to exploration and development of natural gas. The House bill will unquestionably lower both our cash flow and our borrowing base by lowering the value of our assets. It will be impossible to predict the amount of the reduction for months, and perhaps years, if litigation results as it surely will. To prevent liquidity problems, even financially secure companies like ours will be forced to drastically curtail drilling.

Of course, natural gas shortages will eventually force prices up if the House committee bill is enacted. Unfortunately, for consumers, the legislation will drive prices to levels in excess of those which would be necessary to assure adequate supplies. It is not producers, but consumers who will be the biggest losers under the House committee bill.

RECOMMENDATIONS FOR POLICY-MAKERS

Mr. Chairman, if this committee wishes to consider actions which will enable our country to realize the enormous potential advantages offered by our undeveloped natural gas resources, there are several things I believe you could do.

First, you could direct the appropriate authorities to fully investigate and dispell the myth of the bubble. Do not bet consumers' dollars on the foresight or independent judgement of the pipeline companies. Those pipelines which have argued the existence of a large and costly bubble with greatest force have a perfect track record -- they have been 100 percent wrong. In the 1970's, they allowed themselves to be caught short on supplies. They believed the resource base to be much smaller than it is. They committed to costly and unnecessary sources such as Algerian LNG and synthetic gas and they bid too much for unregulated domestic supplies. Now they wish to terminate contracts which they entered into freely and without coercion. If they succeed, the result will be to destroy the independent gas producing industry which is the touchstone for development of all future gas supplies.

Second, I hope those responsible for determining federal energy policy will do so with an understanding of the reality of abundant, potential natural gas supply. Many billions of tax dollars have been spent in the name of energy independence -- an essential national goal. But in the future, tens of billions in consumer as well as tax dollars could be saved if only there were a national decision to develop to the fullest, our abundant natural gas resource base.

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[25] Estimate of Natural Gas Supply Association, "Gas Drama Reaches Climax," Energy Daily, April 13, 1984. P. 4.

Third, we must continue the drive toward free market pricing of natural gas -- and especially to honor the commitments made to producers in the Natural Gas Policy Act. Government regulations never produced a single cubic foot of natural gas. The consumer's most important ally is not the government regulator, but instead the thousands of independent entrepreneurs who are risking billions in capital to deliver energy supplies to America's homes and businesses.

Fourth, and finally, it is imperative that you open up the market to natural gas. Let users decide which fuel is most efficient and cost-effective without artificial government end use constraints.

CONCLUSION

Let me again express my appreciation to you, Mr. Chairman, for scheduling these hearings. I hope they will serve as a springboard to further examination of the realities and needs of the energy industry. However, let me emphasize that for independent producers, this is a precarious time. For whatever reasons, measures are being considered -- the best example is the House bill I have described earlier in my statement -- which would make matters worse. I would therefore conclude with a strong note of caution for those who must make energy policy -- look before you leap. What may have superficial appeal to members of the House facing re-election this fall, will look like a terrible, unbelievable mistake to consumers who must live with the consequences a year or so from now. Upon reflection, I hope you'll agree with me that the best course for our country would be a 1-year moratorium, a period for fact-finding and for reflection, before moving forward on any major natural gas legislation. You have raised the right questions and I earnestly hope that your colleagues in the House as well as the Senate will pause for consideration of the issues and problems raised during these hearings today.

Thank you.

Senator MURKOWSKI. Thank you very much, Mr. Wolf.

I think that your testimony has very pointedly brought out a growing concern, particularly from the independent companies, on the significant and very difficult position that would be brought about as a disincentive for the industry if the proposed committee bill before the House comes into reality.

Did you have an opportunity to testify before this committee on gas deregulation?

Mr. WOLF. No, sir.

Senator MURKOWSKI. I think we had 30 markups; and, unfortunately, there was less than a consensus within the industry group. And having been a member of the full Energy and Natural Resources Committee which sat for days and days, weeks and weeks, I marvel at the patience of the chairman, Senator McClure, who is chairman of the full committee, for attempting a noble democratic experiment that, obviously, and unfortunately, did not resolve itself in a consensus.

Now, whether the chairman is prepared again to suggest that the industry go in the back room and not come out until they have consensus, I don't know, but that would be respectfully my suggestion to him the next time around.

But I assume you are prepared, Mr. Wolf, to testify before the House hearings.

Mr. WOLF. Yes, sir.

Senator MURKOWSKI. You feel pretty much that the estimates are understated.

Mr. WOLF. Yes, sir.

Senator MURKOWSKI. Based on the fact that your company has been able to carve a market share in a very competitive atmosphere through, I assume, hard work and vision, and perhaps a little luck.

Mr. WOLF. I'd say a lot of all those things.

Senator MURKOWSKI. I notice you're not in Alaska. Is there any reason?

Mr. WOLF. It's totally noneconomical to be there.

Senator MURKOWSKI. I see.

Mr. WOLF. As far as looking for natural gas. Who do you sell it to?

We're in the business of selling Btu's. And people always gripe that no matter at what price you're selling gas for—and we're selling it very cheap today, people complain about price. And I don't see how you can bring Alaskan gas down at a fair competitive price in lieu of today's market conditions.

And I think the average independent company such as ourselves, we live on cash flow. We cannot afford to get involved in long, expensive, very slow payout projects.

And Mr. Wheeler is an expert of what goes on in Alaska, and he's sitting up there with 26 Tcf of gas and no place to go with it.

A company our size just can't afford to do that.

Senator MURKOWSKI. In other words, the implication indirectly is that you couldn't afford to sit on gas without marketing it, and somebody else might be able to?

Mr. Wolf. I said our segment of the industry, which is the independent producers, we're constrained by cash flow to handle our operations and——

Senator Murkowski. And you don't feel you could go up there and explore and if you find it, sell it to Mr. Wheeler?

Mr. Wolf. I'm not sure. We haven't negotiated that, but I don't want to give him the opportunity, because I don't think I'm going to go there.

Senator Murkowski. I don't know that Mr. Wheeler's made any offers either, in all fairness to him. But we have Mr. Dyer that's willing to go up and look for oil.

Mr. Wolf. I was impressed by his statement that said he's the operator of two nonoperating operations. [Laughter.]

Senator Murkowski. If I were curious, I'd ask you to submit for the record, Mr. Dyer, just how you do that, but I'm not that curious, that's your own business.

I do appreciate your testimony, Mr. Wolf. And one more time Inex-ico?

Mr. Wolf. No, sir, try one more time.

Senator Murkowski. In echo?

Mr. Wolf. No, no. One more time.

Senator Murkowski. Well, just a minute. In echo?

Mr. Wolf. No. Inexco, I-n-e-x-c-o.

Senator Murkowski. In ex ico?

Mr. Wolf. No. Try one more time. [Laughter.]

Senator Murkowski. I flunked phonics in school, as you can see. It's Texaco with an "in" on it. Is that right?

Mr. Wolf. It's—it's—whew—Inexco.

Senator Murkowski. He's having a difficult time with it now.

Mr. Wolf. Years ago we used to be one of the most succesful uranium companies and our name was called International Nuclear Exploration Co. Then we got in the oil business, and the SEC called us up one day and said, what's an international nuclear exploration company doing in the oil business? Why don't you trim your name or get a new name?

So if you will think of International Nuclear Exploration Co., and abbreviate that to Inexco, you can't miss.

Senator Murkowski. Inexco.

Mr. Wolf. That's right. [Laughter.]

Senator Murkowski. Thank you. [Applause.]

I deserved that. I won't try it anymore though.

Our next witness is Mr. Hefner, according to the sheet in front of me, although you two have——

Mr. Hefner. If you don't mind, I'll sit out of order for a moment so that I can point at a chart.

Senator Murkowski. Oh, that's fair enough.

Mr. Jensen, president of Jensen Associates. We welcome you and——

Mr. Jensen. I have the same problem.

Senator Murkowski. Well, I don't care. You gentlemen decide whatever's fair.

Mr. Hefner. OK. I'll just go right ahead.

Senator Murkowski. OK. Mr. Hefner, chairman of the GHK.

Mr. Hefner. Pronounced exactly right.

Senator **Murkowski**. Thank you.

STATEMENT OF ROBERT A. HEFNER III, CHAIRMAN, THE GHK COS.

Mr. **Hefner**. Thank you very much, Mr. Chairman, for what I believe to be a very, very important hearing that I hope leads to some new understanding on the North American natural gas resource base.

I'm certain my full statement will be put in the record.

Senator **Murkowski**. It will be entered in the record.

Mr. **Hefner**. As a bit of background. The GHK Cos. were formed in 1959, and we have been totally natural gas oriented since our beginning, and explorers basically of one gas-proned province, the Anadarko Basin, which will be on some of these maps that I have with me.

We have one oil well.

Senator **Murkowski**. Did you find that looking for oil?

Mr. **Hefner**. Yeah, I found it looking for oil.

My personal background is that I'm an exploration geologist and geophysicist who, unlike my grandfather who went to Spindle Top when it came in, was an oil man and looked for oil; and, unlike my father, who continued in that line, I have focused my lifetime on the search of natural gas, not oil.

And I think equally more important—equally important if not more important to this hearing is, I have also spent a lifetime exploring for a fuller understanding of natural gas in its differences from oil; and in a search of an understanding of the natural gas industry, which for many years I didn't realize did not exist. I think actually it's only been born in the very recent years.

The essence of this learning is that natural gas is geologically, technologically, and certainly economically and politically different from oil.

I believe that until these differences are clearly understood and assimilated, that all historically and statistically based natural gas resource projections will be fatally flawed with oil-related distortions.

I think Mr. Plotkin alluded to this in the work at the OTA.

And fatally flawed so toward the conservative as I believe to be useless.

I suspect you could say that the essence also of my lifetime of work is that I respectfully have to disagree, Mr. Wheeler, with everything Exxon said on the natural gas resource base.

Senator **Murkowski**. That's the prerogative of an independent.

Mr. **Hefner**. Yes. [Laughter.]

Mr. **Wolf**. Let us look for a second at some of these differences. The significant geologic difference, for instance of a methane resource base versus oil.

Methane is globally pervasive in sedimentary rocks. It's not limited in commercial quantity by the unique trapping mechanisms necessary for the commercial production of oil.

Therefore, I believe, for instance, that the entire idea of organizing data by gas fields is oil-related and unnecessary leading to oil distortions.

Even as I heard this morning earlier in Mr. Plotkin's statement the understanding of individual traps may no longer apply to the understanding of the methane resource base. I think an example of this is clearly shown by some of these maps that I have here beside me.

This is a map of the Western Anadarko Basin in the year 1955, with the red color indicating gas fields, and the green color indicating oil fields.

You will notice that—oh, by the way, the most prominent north-south, or vertical black line is the Oklahoma-Texas Panhandle border. Oklahoma City would be just to the right of the map, Amarillo just to the left of the map. It will give you an idea of the proportion in scale.

You will notice that basically there's a blob of red circling the western limits of the Anadarko Basin which, at that time, was developed as the Hugoton Panhandle Gas field; a very shallow field which was commercial at that time of development.

Bob, would you let us have the next chart, please.

There's a big gap from 1955 to 1972. But during that time, I spoke to, I believe, every major oil company, and not one company at that time would participate in projects, nor did they believe, for various reasons, which I will continue to describe, that there would be any commercially available natural gas in this basin, or any significant commercially available natural gas in this basin.

And as we look at the balance of the charts, 1972 to 1976, to 1979, and more recently, 1982, and again, 1983, you will see the red continues to grow and continues to fill in the entire map.

Senator **Murkowski**. It looks like it's pretty hard to miss.

Mr. **Hefner**. It is.

The point is, as I said, methane is pervasive in sedimentary rocks and, therefore, you don't miss when you drill for methane. You might miss commercially available methane, but you don't miss and hit water like you do in oil, which is uniquely trapped in the ground.

In fact, I would say that the Anadarko Basin, if we have to use the terminology of field, is one giant gas field, which I believe we would say has been found within the time of increasing favorable economics for natural gas. And, therefore, the statistics that no giant gas fields have been found are in error.

I also personally, as a geologist, would include the Anadarko Basin as one giant stratigraphic trap. And, therefore, the idea that giant stratigraphic traps do not exist is wrong; for it is highly probable that in many of the more gas-prone basins, they will become one giant gas field.

Other problems that relate to these differences are that, for instance, in the OTA studies they quoted Dr. Hubbard. He's probably right on his remaining resource estimate of oil, but there's no relationship, no oil-gas relationship or ratio which I believe will ever be found that you can relate by ratio the abundant Btu's in the form of methane around the globe to inequantities of oil.

A technological difference. Let's look at a very simple technological difference—and it's so simple, you wonder why it isn't understood more often, but it isn't. Boyle's law, gas, methane is compressible; oil is not.

When we drill to 20 thousand feet in the Anadarko Basin, if we were to find some oil—we won't, because it's not an oil province, but if we were to find a barrel of oil—and you can that deep in offshore provinces in more recent sediments, and bring that barrel of oil to the surface, we would have a barrel of oil.

But on the contrary, when we find and produce one barrel of natural gas, methane, from the pressures often experienced at those depths, and bring that barrel to the surface, we may have up to a thousand barrels of methane.

The implication of this simple technological difference is that as you drill deeper, the same reservoir will hold a lot more natural gas.

Another distortion that we have emaninating from an oil industry that crops up in our thinking is that by far the majority of the gas you saw added to this one province in the Anadarko Basin over the recent years could never—or is produced from rocks which could never produce a barrel of oil; couldn't even move through those rocks, because oil is bisqueous and it takes a lot more energy to move through the same quality of reservoir.

As a matter of fact, in 1972, many of the scientists related to the major oil companies who had these data available to them—I know Conoco published some very prestigious studies in the AAPG—but each of them could prove that because as you go deeper rocks are compacted by the weight of the overburden, that there could be no reservoir that could contain commercial quantities of oil at the depths the majority of this production is now producing from.

And, of course, equally self-evident are the political and economic differences. I know you know all about them, but let me talk about them for a moment.

Most all the gas that's been consumed in the past three decades has been found in the search for oil—just as you were talking about in Alaska, and has been produced along with oil, and it's been subject to stringent and very low price controls, which meant that both the production, the transportation and the consuming segments paid little attention to the commodity price during most of those years. And thus, as we all know, demand/supply was distorted, enormous demands were built up where supplies were continually dwindling.

And, therefore, it is for these reasons that I believe all statistically related and econometric approaches to estimating the natural gas resource base are fatally flawed with the inseparable association with oil economics as to literally be both unrealistically conservative and useless.

I think another good example——

Senator MURKOWSKI. Mr. Hefner, I'm going to have to interrupt you now. They just called a vote, and I'm going to recess the hearing for a few minutes until I can get back.

Mr. HEFNER. That's OK.

Senator MURKOWSKI. Thank you. And I apologize.

Mr. HEFNER. I'll be here.

Senator MURKOWSKI. Thank you.

[Recess taken.]

Senator MURKOWSKI. Mr. Dyer, I believe you have a time commitment.

Mr. **Dyer**. I do.

Senator **Murkowski**. We would certainly urge that you keep your commitment, and I apologize for keeping you.

Any time that we get into a vote, why all kinds of things can happen, and they did.

So please, those of you who have been kind enough to sit through this much, you certainly may be excused, and we may be calling on you for specific submission on questions for the record.

And who else has to leave? Mr. Wolf?

Mr. **Wolf**. Yes. We thank you very, very much.

Senator **Murkowski**. It's been a pleasure. Thank you, gentleman, from contributing so significantly to the record.

Mr. Hefner, I believe you were in the midst of your presentation when the bell went off.

Please proceed.

Mr. **Hefner**. Correct. Thank you.

Where I was to the point of saying that for those reasons I had talked about earlier, that I believe that all the statistically related econometric approaches to natural gas resource estimation are fatally flawed with their association to oil economies, and are so unrealistically conservative as to really be useless for policy decisions.

I was about to turn to this chart on your left of these charts, which is entitled "Projected Production Capacity Versus Actual Production Capability."

Senator **Murkowski**. I have it here in my book.

Mr. **Hefner**. And it shows the actual U.S. production capability at the top with an orange or yellow line. And then it plots at the date and time that the estimates were made in either blue or green the projections made by various agencies or individuals, generally in government, based on various statistical analysis. I can't see them labeled from here.

Senator **Murkowski**. I have them in front of me.

Mr. **Hefner**. Do you have them there?

Senator **Murkowski**. Yes.

Mr. **Hefner**. All right.

A good fellow that I've always taken aim at, and I guess it's because he was the first one I challenged on this, it goes back to the early 1970's, as you will see, is Zareski's econometric projections when he was economist with the Federal Power Commission, which are the red lines.

And you will see at that point in time the reasonable, quote, unquote, "optimistic" line goes to the bottom of the page.

He thought that the other line which shows about 50 percent of the U.S. ability to produce today was unreasonable and speculative, where you can see that it was totally conservative.

Now, I'm not here to say that those approaches are handled wrong, that the statistics have been manipulated in any way. What I am here to say is that those statistically oriented resource projections are very good resource projections of the amount of natural gas that will be found in the future exploration for oil, like in Alaska, and will be produced along with oil; but, they totally overlook these vast gas-prone sedimentary basins, such as the Anadarko basin that I've talked of here today and shown you the maps of, the very large smack overtrend from Florida, Alabama and all the way through into Texas of the gulf coast, the Tuscaloosa trend, the Overthrust Belt of the Rocky Mountains, across the entire United States, the Arcoma basin, the mirror image of this basin still in Oklahoma and Arkansas, the entire Appalachian area. These have not been included in these statistical approaches to resource estimation of natural gas, but are included in the geologically-oriented projections of the natural gas resource base, which I believe the most confident and prestegeous of those to be the Potential Gas Committee, who was represented by Dr. Kent here earlier, and additionally, the USGS, the Gas Research Institute, and others.

However, these forecasts were called by the OTA and others, quote, "The most optimistic of major assessments;" where in reality, for the reasons I've stated here, the significant differences between oil and gas, methane, in fact, I believe those estimates to be at the conservative end of the zone of reasonableness.

Let me tell you quickly—I don't want to take too much more time, I know it's late—two little stories though that happened—real-life stories that happened to me, and began to open my eyes and clarify my understanding in these differences between natural gas and oil.

During the debate leading up to the Natural Gas Policy Act there were also some resource hearings—and the resource base was very important, because one part of that legislation was even to prohibit the burning of natural gas because of its limitedness of supply.

And I had looked at the AGA's, the American Gas Association's estimates of the resource base, and estimates of the production capacity of the U.S. forecast into the future.

I felt they were very conservative, and yet I looked at the most optimistic projections by the AGA's economists and I knew something was wrong.

So we went to them and we said, let's look at these figures, let's get to the root of it, let's find out why the AGA has such pessimistic projections which they call optimistic.

Well, the guts of the story is, we asked how they were done. And one of the key factors was finding rates. You'll always hear finding rates talked about.

We asked him when? And he said—and this sounds sensible—he said that he had used the highest finding rates ever experienced by the industry to project his optimistic estimations of the remaining resource base and how much gas would be available, but there was one thing lost in that.

I asked him when that was. He said it was in the mid-1950's. But the statistics didn't realize, and the economists didn't realize that in the 1950's there was an oil industry looking for oil in oil provinces and, therefore, it's my opinion that his optimistic projections were limited by an industry which economically was exploring for oil where you don't find so much gas.

Another problem is that the industry at that time never made any risk judgment based on the price of gas. They didn't accumulate and expend capital based on the price of gas, they did it based on the price of oil. Gas was a byproduct.

It was during that same mid-1950's—late 1950's, I was with Phillips Petroleum Co., and at that time, at one time I spent time in Bartlesville in their economic analysis section, and we would look at the economics of every project the company was about to take on related to drilling, exploring, and developing. I soon learned that the price of natural gas had no meaning. We were not allowed to use it in our economic assessments of a project. It was only the well-head price of oil.

Gas, yes. We would say sure, the Andarko Basin was one of the places I did such economic analysis for Phillips Petroleum Co., a gas-prone province. Sure, there's going to be gas there, but it's a plus factor, it might pay the overhead.

So remember, that during all the years that we rely on for statistical analysis, all—most all of the capital expended was based on the economics of oil. And the risk judgments taken directed not only to finding oil, but were based on the economics of oil.

So the results of my lifetime looking for natural gas, understanding natural gas, understanding the economics of natural gas, have brought me, as I said, to believe that such estimates as the USGS, Potential Gas Committee, and others, geologically oriented are not only the best, but at the lower end of the realm of conservatism, as resource estimates generally always are.

My best judgment—although, I'll confess not to be an expert on either the entire U.S. supply, North America, or the globe, but my best estimates is that the estimates that had been made by other experts geologically based in the range of a 1,000 to 1,500 trillion for the United States are sound, and that North America's supply could easily be twice that. I don't think Canada's begun to be tapped. Mexico hasn't been scratched.

And so my intuition tells me, as a natural gas explorationist and geologist, that North America contains at least twice that of the United States, or somewhere in the range of 2,000 to 3,000 trillion.

And I cannot help but believe that the misconceptions of resource base and the lack of understanding between these differences of oil and gas have brought us decades of economic and resource distortions; have brought us certainly a lot of political and economic chaos; have brought us legislation, now proven to be totally unnecessary, such as the Fuel Use Act and incremental pricing; have brought us significant capital—huge capital expenditures on unneeded and possibly technologically unsound at this time nuclear plants; it's brought us the billions of dollars of investments by U.S. companies in LNG that were not needed; it's brought us the Synfuels Program, which is scheduled, I guess, to spend how much—$20 billion, $25, $30 billion in the next years on programs that I assess, because of my understanding of the resource base, will always be uneconomic and unnecessary.

But I also just as strongly believe that out of this political and economic chaos will come a very strong, vertically integrated, competitive natural gas industry that I think's being born right today that will be able to compete with new technological innovation with the oil industry for market shares, with the nuclear industry, with the coal industry, and I think successfully compete.

History does repeat itself, and 50 years ago you saw the same thing in oil. In 1928, no one thought there was enough to fuel a great industrial economy that was perceived by everybody correctly. The price went up. People drilled, the Gettys, Sinclairs and others, because it was profitable; but, at the same time, we went into—the 1929 crash came, we went into a recession. The country had all of a sudden a glut of oil. The price began to drop, it hit 10 cents a barrel, hit 6 cents a barrel; political and economic chaos, the beginning of conservation laws.

But out of that, market forces caused what was not a cohesive industry to become one, to become the vertically integrated, very efficient oil industry, which took market shares away from coal and took market shares away from, then, wood.

So I think the same thing's happening today in natural gas, and we're giving birth and feeling the pains, to a natural gas industry.

Now in conclusion, I think that the understanding of the resource base will allow us to take some policy decisions that are necessary. And I, too, like Jaye Dyer and Erving Wolf, believe that for the first time this country must adopt a promethane policy; a promethane policy which will contain an understanding of the world's most abundant, environmentally desirable and economic fuel, methane.

That policy would contain, I believe, such things as first, the immediate elimination of laws and regulations prohibiting and limiting the use of natural gas. I think it's no longer conscienable to leave those laws on the books and hold them hostage to some other sorts of natural gas legislation that nobody, neither Congress or the industry, can agree on.

Another point. As you heard earlier, Mr. Wolf and Mr. Dyer said that we independents, who are literally the production sector of the natural gas industry, live on cash flow.

Recent banking policies, which have been stringently prejudice against U.S. natural gas lending, have caused us enormous problems. And I think that those policies should be looked at again in the light of domestic methane abundance and the national security of benefits of reducing oil imports and large trade deficits.

Besides, I don't think it's fair when they look at foreign loans the way they do, giving a helping hand to foreign producers and those who produce foreign oil and their economic associates. Although I'll agree, life and politics aren't always fair.

The policy should provide tax incentives, in my opinion, to develop methane fuel's integrated energy systems, and the conversion of methane to clean, liquid fuels.

And that money can come out of what's already budgeted. Why not shift the billions of dollars that are going to be spent on uneconomic programs of synfuels toward these tax incentives?

Continuing efforts must be made in accelerating efforts to deregulate substantially the Nation's natural gas transmission and distribution industries, so that buyers and sellers can get economic signals and do business together.

And, as I know Betsy Miller would know I would say, end the 20-year congressional war over natural gas pricing policy. Give us some political certainty to do business in for once. And, for God's sake, can't we rejoice in the peace of de facto deregulation which is causing our industry either to renegotiate or go broke?

I'll remind you that the oil industry integrated itself and became efficient, not because we passed omnibus oil legislations that dealt with all the political and economic chaos that the oil industry was having 50 years ago, but it was the economic troubles that restructured that industry.

And, Senator, for Alaska, of course, I've never seen any reason to harbor those resources of natural gas within Alaska. I thought that the country for many years needed to export, at least from Alaska either to this country—although I don't think it's economic, nor will it be if you believe in a resource base as I do in the lower 48, but I think that's way past time to export those natural gas resources into the world economy.

We had attractive opportunity, a window of opportunity which unfortunately may be passed for the near term because I believe Japan and South Korea and others who could use that gas have contracted for significant quantities; but, had we sold it at that time, my goodness, wouldn't the balance of trade deficits be in better shape with Japan?

That concludes my remarks, and I thank you.

[The prepared statement of Mr. Hefner follows:]

STATEMENT OF ROBERT A. HEFNER III

INTRODUCTION

My name is Robert A. Hefner III and I am Chairman of The GHK Companies located in Oklahoma City. The GHK Companies have 25 years of experience in the exploration for development and production of natural gas in tne Anadarko Basin. We are a unique production company in that we have focused, for our entire history, on natural gas -- not oil. We have only one oil well, and although the news media generally associates GHK with "deep gas" operations, one-half of our gas is shallow.

I am pleased to be invited to appear again before this Subcommittee and you are to be commended, Mr. Chairman, for undertaking these hearings, because no more fundamental question can be asked by the Congress, in the welter of arguments and figures surrounding natural gas legislation, than how large is the natural gas resource base?

Not only is this precisely the moment in our national debate over a gas bill to focus on future supplies, it is also important to focus on understanding how previous misconceptions about our gas resource base have led to seriously misdirected national energy policies. Mr. Chairman, it is my deep belief that United States history will eventually record the misconception of limited natural gas resources to be so far reaching and economically fundamental as to be among one of the most economically, geopolitically and geostrategically costly of the post-World War II era. Thus, today's hearings could serve as the beginning of an enlightened period in our history when the production and use of the world's most abundant, environmentally desirable and economic fuel is encouraged.

I am an experienced geologist/geophysicist who, unlike my grandfather and father who spent their lives as independent oil men, have spent my entire career in search of natural gas. Additionally, and of even more importance to this hearing, I have also devoted myself to the exploration of understanding of the differences between oil and natural gas, the understanding of the natural gas industry (which I found not to exist until recently) and the understanding of the pervasive effects of energy, and particularly natural gas, on our economy and security. It is for these reasons that I believe I am as qualified as anyone to predict the undeveloped natural gas resource base for the Anadarko Province. And, moreover, I believe what I have learned from over two decades of natural gas resource projections by various "experts" in the Anadarko Province applicable to all of North America and, for that matter, the entire world. The essence of that learning is that natural gas is geologically, technologically, economically and politically different from oil; and that unless these differences are clearly and fully understood, we will not be able competently to assess resource projections. For example:

(1) a significant geologic difference is that natural gas is literally pervasive throughout the world's sediments and, therefore, not limited in commercial quantity by the unique trapping circumstances necessary for the commercial production

of oil. Thus, the entire idea of organizing natural gas data by "fields" of various sizes, although applicable to oil because of the specificity of its trapping mechanism, has nearly no meaning in quantifying or projecting non-associated natural gas data. As the following Anadarko Basin gas maps show, this natural gas province is one "significant"[1] gas "field" and therefore the "common understanding" that there are no lower 48 giant gas fields presently under development is incorrect, because in reality, each gas prone province may be one giant field. Additionally, there is no known scientific theory for the existence of a global oil/gas ratio between non-associated natural gas and oil. I believe the world to contain many more times the number of BTU's in the form of commercially available non-associated methane than it does BTU's in the form of commercially available oil.[2]

(2) A significant technological difference between oil and gas is that natural gas is compressible and oil is not (Boyle's law). Therefore, gas can be produced commercially from rocks from which oil cannot even move. Additionally, a barrel of oil produced from 20,000 feet is still a barrel of oil at the surface; whereas a barrel of gas at 20,000 feet can be as many as 1,000 barrels of methane at the surface. Thus as one drills deeper, the quantity of gas recoverable from any given reservoir is increased by each additional increment of pressure (between 0.5 and 1.0 psi per foot of depth).

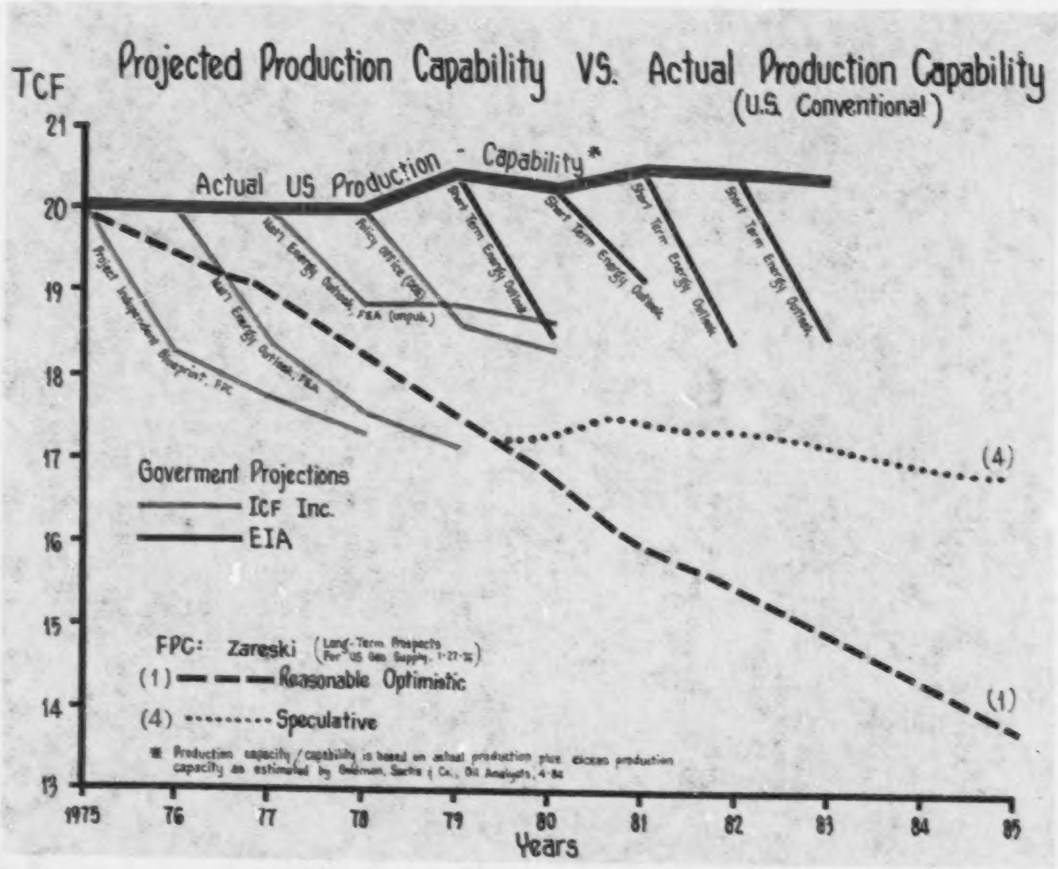
(3) A significant political/economic difference between oil and gas is that nearly all of the gas consumed in the past three decades has been found either during the search for oil or produced in association with oil while subject to stringently low price controls which continually maintained the end use price for natural gas at barely a fraction of the cost of other competing energies. Therefore, all statistical approaches to determining the natural gas resource base are so distorted by their economic association with oil as to flaw totally the results and to be unrealistically conservative. The Rand-Hubbert-Zareski[3] and other statistical approaches are probably a realistic assessment of the undeveloped natural gas in the United States which remains to be either discovered in the future search for oil or produced along with yet undiscovered new oil fields. Therefore, because the "lower 48" is a very "mature" oil province, the extremely conservative projections related to oil statistics and oil understanding are approximately correct. However, those statistical studies ignore all the "lower 48" relatively undeveloped frontier natural gas provinces such as the Anadarko Basin, the Tuscaloosa Trend, the Smackover Trend, the Overthrust Belt, the Arkoma Basin, the Appalachian Province, and other areas. It is therefore critically important to understand that

these vast natural gas provinces, which are overlooked in oil-distorted statistics, are included in the most credible geologic estimations made by the Potential Gas Committee, the Institute of Gas Technology, the Gas Research Institute, and the United States Geological Survey.[4] The most credible projections are those made by experts who look forward and are expert in looking forward, not those who are expert in looking backward; for, although that of the Potential Gas Committee estimate is often described, as it was in the 1983 publication of U.S. Natural Gas Availability[5] by the Office of Technology Assessment, as one of the most "optimistic of the major assessments," it is in reality entirely within the range of "conservatism."

Another problem with the statistically-based estimations such as the Rand-Hubbert-Zareski reports, as exemplified by the accompanying chart entitled "Projected Production Capability vs. Actual Production Capability," is that, they are not related to gas! You may say that this is stating the obvious, but let me relate two stories to clarify my meaning.

First, during the natural gas resource debate associated with and leading up to the Natural Gas Policy Act and the Fuel Use Act, I asked an economist with the American Gas Association why his optimistic resource projections for natural gas were, to my mind, so conservative. He replied that he had pushed the limits of optimistic projection by using "finding rates" equal to the highest ever achieved during "the industry's" (he meant the oil industry's) entire history -- "during the mid-1950's." Is it not interesting that he had not realized that the entire "industry" in the 1950's was looking for oil in America's oil provinces, not a gas industry looking for gas in America's gas provinces, and that all wells drilled during those years were based on economic returns pegged to the price of oil, and that the price of gas was not even a factor in the exploratory risk judgment nor in the formation of risk capital. Second, as a young geologist, I worked for a short period of time in the economic analysis section of Phillips Petroleum Company, participating in the economic analysis of projects proposed by that organization for exploratory or developmental drilling. I learned that, in the case of Phillips, the price of natural gas was not allowed to be used in the economic calculations or risk assessments but simply called a "plus factor" if the project was thought to have natural gas potential as well as oil.

Other distortions still present in recent projections by the major oil/energy companies and a few natural gas transmission companies are due to "corporate momentum" created by the past expenditure of billions of dollars and the economic necessity to make the most of possible return from this spent


Projected Production Capability VS. Actual Production Capability
(U.S. Conventional)
TCF
21
20
19
18
17
16
15
14
13
1975
76
77
78
79
80
81
82
83
84
85
Years
Actual US Production - Capability*
Project Independence Blueprint, FPC
Nat'l Energy Outlook, FEA
Nat'l Energy Outlook, FEA (unpub.)
Policy office (DOE)
Short Term Energy Outlook
Short Term Energy Outlook
Short Term Energy Outlook
Short Term Energy Outlook
(4)
(1)
Goverment Projections
ICF Inc.
EIA
FPC: Zareski (Long-Term Prospects For US Gas Supply, 1-27-86)
(1) Reasonable Optimistic
(4) Speculative
* Production capacity/capability is based on actual production plus excess production capacity as estimated by Goldman, Sachs & Co., Oil Analysts, 4-86

capital for each institution's stockholders. It is for this reason that major oil companies, which are heavily invested in refining and marketing of oil and whose exploration focus for decades has been toward offshore oil and foreign oil, have a more optimistic view of the offshore provinces and the Alaskan oil and gas frontier than the "oil mature" lower 48 states. It makes no more sense for GHK to estimate the oil potential of these provinces than it does for Exxon to estimate the remaining methane reserves in the Anadarko Basin. The same logic generally applies to "gas" companies heavily invested in LNG and is a subject expanded upon in my Aspen Institute remarks on the "Gas Energy Option" of 1978 (Attachment A).

Let the record clearly show that I am not condemning these econometric statistical approaches to resource projection but simply stating, emphatically, that in the case of remaining North American natural gas resources, there are no relevant statistics available before the mid-1950's when significant capital formation and risk judgment were both based on the wellhead price of natural gas, not oil, and focused on the exploration and development of natural gas, not oil. These gas relevant statistics only began coming into being in the mid-1970's as economic forces overcame political resistance and the intrastate price of natural gas began to rise, leading eventually to the Natural Gas Policy Act and the beginnings of market pricing and market mechanisms relative to natural gas.

Although the "statistical indications" since 1975 tend strongly to support the various "geologically-oriented" and "optimistic" range of assessments of remaining natural gas, these data have largely been excluded in recent forecasts due to the time lag in their coming into the public record.

For a specific example of this problem, one can compare recent Anadarko Basin realities to data published by the American Association of Petroleum Geologists (AAPG) in November of 1982 and referred to more recently by the Office of Technology Assessment as "the primary public record" in its September 1983 technical memorandum on U.S. Natural Gas Availability.[6]

The AAPG statistics seem on their face to understate our nation's unassociated gas well potential in light of recent Anadarko statistics available to us. For example, the following table indicates the number of individual gas wells (not fields) located in a large part* of the Anadarko basin which either have produced or are estimated will produce** more than 6 BCF of gas and therefore are individually equal to a "significant field" as defined by the AAPG.***

AAGP BULLETIN 66/11, November 1982

Table 13.—Historical Record: Number of New Gasfield Discoveries Proved After Six Years To Be of Significant Size

Year drilled	Total wells reported as gas wells at end of year of completion	Number of fields in each size classification[a] after 6 years development history							Total significant size gasfields	Percent of significant gasfields in all gas discoveries	Total new field wildcats drilled	Percent of significant gas finds in total new field wildcats drilled
		A	B Significant	C	D	E	F	Total	A-D Inclusive (A+B+C+D)			
1945	103	3	2	11	33	24	20	93	49	52.69	2,905	1.69
1946	78	1	2	7	22	29	12	73	32	43.84	2,995	1.07
1947	106	5	5	4	30	35	19	98	44	44.90	3,325	1.32
1948	116	3	3	7	33	35	19	100	46	46.00	4,087	1.13
1949	121	8	7	8	34	43	12	112	57	50.89	4,238	1.34
1950	118	4	4	8	28	44	19	107	44	41.12	5,149	0.85
1951	155	10	4	10	41	57	16	138	65	47.10	6,044	1.08
1952	171	10	7	7	44	65	15	148	68	45.95	6,440	1.06
1953	177	3	3	6	40	89	18	159	52	32.70	6,634	0.78
1954	248	4	1	12	51	104	39	211	68	32.23	7,033	0.97
1955	228	2	3	11	33	107	43	199	49	24.62	7,743	0.63
1956	230	2	4	5	52	92	26	181	63	34.81	8,436	0.75
1957	247	9	5	15	70	105	30	234	99	42.31	7,556	1.31
1958	262	3	6	9	55	143	25	241	73	39.29	6,618	1.10
1959	308	4	1	6	51	135	28	225	62	20.13	7,031	0.88
1960	240	6	2	9	63	135	22	237	80	33.76	7,320	1.09
1961	316	4	3	4	35	156	40	242	46	18.59	6,909	0.66
1962	317	3	4	11	61	161	52	292	79	27.05	6,794	1.16
1963	240	4	1	7	38	124	41	215	50	23.26	6,570	0.76
1964	252	4	1	11	37	136	37	226	53	23.45	6,823	0.80
1965	234	1	3	10	38	142	30	224	52	23.21	6,175	0.84
1966	232	1	3	7	36	142	12	201	47	23.38	6,158	0.76
1967	179	4	5	6	26	111	12	164	41	25.00	5,271	0.78
1968	126	1	5	7	27	83	14	137	40	29.20	5,205	0.77
1969	190	3	2	4	35	116	14	174	44	25.28	5,956	0.74
1970	184	5	4	3	25	79	14	130	37	28.46	5,069	0.72
1971	202	2	3	3	38	102	12	160	46	28.75	4,463	1.03
1972	273	3	2	6	47	187	0	245	58	23.67	5,086	1.14
1973	416	2	6	10	57	284	0	359	75	20.89	4,989	1.50
1974	445	0	2	6	51	329	0	388	59	15.21	5,652	1.04
1975	448	3	0	1	64	336	0	404	68	16.83	6,104	1.11

[a]Size classifications: A = >300 BCF
B = 150-300 BCF
C = 60-150 BCF
D = 6-60 BCF
E = <6 BCF
F = noncommercial

SOURCE: R. R. Johnston, "North American Drilling Activity in 1981," AAPG *Bulletin*, vol. 66/11, November 1982.

	Wells Having Produced >6 BCF	Wells Est. to Produce >6 BCF	Total Wells	"Wells on Line" After 1-1-75
Year end 1975	557	561	1118	--
7-1-80	832	493	1325	207
1-1-84****	965	572	1537	352

Note that there is a 145 "Wells on Line" increase from 7-1-80 to 1-1-84.

* The area covered by Dwight's - Energydata[7] publication and excluding of the Hugoton, Panhandle and Red Cave fields.
** Estimated by GHK staff from pressure decline data as produced by Dwight's.
*** The American Association of Petroleum Geologists defines a significant gas field as one that will produce six billion cubic feet of gas in its lifetime as defined in the preceding chart.
**** Subject to revisions and additions.

The preceding maps depicting in time sequence the gas development of the Anadarko Province clearly indicate, among many other significant facts, both the futility of dealing with gas fields and their boundaries and the certainty that, for all practical purposes, the Anadarko Province, like many other gas provinces, will become simply one "gas field" just as the northern portion of the Eastern Seaboard is often referred to as "BosNYWash."

In summary of this point, I fully embrace the geologically-related natural gas resource estimates of my colleagues at the Potential Gas Committee, the Gas Research Institute, the U.S. Geological Survey, and the Institute of Gas Technology as constructive, conservative estimates of the highest integrity and, therefore, reliable for national economic policy decisions. In today's world of stressful economic and political circumstances resulting from the geopolitical and geostrategic implications of global energy production and use, it is no longer conscionable to base our national political and economic policies on any other understanding than that of an abundant North American, as well as global, natural gas resource base.

It is for these reasons and my own intuition resulting from a lifetime in search of natural gas and understanding of natural gas that I predict the remaining U.S. natural gas resource base to be between 1000 and 1500 TCF and that of North America to be at least double that, > 2000-3000 TCF.

THE TRANSITION FROM AN OIL-BASED TO A METHANE-BASED ECONOMY

The lower 48 states and offshore areas -- and increasingly the world at large -- are maturing as an oil province. Oil reserves are declining inexorably, as are the reserves of associated gas. The spate of mergers in the oil industry, by which major companies are trying to buy oil reserves rather than find them, is an indication of the continuing difficulty of economically and politically maintaining present levels of oil reserves and consumption.[8] On the other hand, natural gas is at the dawn of the integrated methane industry, emerging distinctively from a past during which associated natural gas was produced as a by-product of the oil industry and distributed to consumers through stringently regulated utilities with little regard for commodity costs.

Let us for a moment use the relevant statistics and lessons of oil to understand the present and project the future. Look back in history -- look back in the history of oil a short 59 years ago to 1925 when most "prestigious" forecasters of oil reserves were predicting there could never be a sufficient oil resource base to fuel the then correctly perceived growth of a great American industrial economy, to a time when many "renowned" geologists still professed that they would "drink all the oil" ever found in vast areas of Texas and Oklahoma, now filled with giant oil fields. Look back to 1928 and 1929 when the wellhead price of oil rose to $1.34/barrel, and brash men, such as Phillips, Sinclair, Getty and others, rejected such pessimism because at $1.34/barrel, the risk of exploration in their minds was justified by the potential for great profits. Look back to the Crash of 1929 and the ensuing Depression that was not felt immediately in the West, because by 1932 the fantastically prolific Oklahoma City Field and East Texas Field and others were in frantic development and produced within the next 2 years an enormous "glut" of oil into the depressed national and global economies. The price of oil fell to 10¢/barrel and then to 6¢/barrel when Oklahoma's Governor "Alfalfa" Bill Murray invoked the theory that "economic waste is conducive to physical waste" and called up Oklahoma's National Guard to enforce a new concept, conservation through prorationing.

It was out of this economic and political chaos that economic forces (not omnibus oil legislation) gave birth to the oil industry and necessitated and created efficient, vertically-integrated oil companies. Thus, just as the "oil industry" emerged as a better and more efficient energy technology to replace coal and wood to fuel the industrialization of America, an efficient vertically-integrated methane industry is today, six decades later, rising out of its post-NGPA economic and political chaos as a better technology which will fuel the energy systems leading our country into the 21st Century.

The realization of the emergence of the methane industry and the reliance upon its globally abundant resource base will significantly reduce existing world economic and political tensions and will lead us toward a "least-cost," environmentally benign, nationally secure energy infrastructure. It will eliminate the "necessity" of world nuclear proliferation at costs too dear, even for the most wealthy of industrialized economies, while reducing the world banking and financial crisis by allowing less developed debtor nations to expand their economies and increase their standards of living through increased per capita energy consumption without large oil imports or major nuclear facilities.[9] It is now time for the United States to adopt a pro-methane policy to assist this fledgling but highly capable industry in its difficult early years of development so that America, with its responsibility of global leadership, can lead the world toward these most noble goals.

Again, history clearly tells us, particularly in America, that human ingenuity proliferates during the emergence of a new industry and multiplies the efficiency of "in hand" technology many orders of magnitude in its early decades. Recognizable analogies are the automobile industry from buggy to race car; the "oil" industry from the crude understanding of water well "exploration" and drilling technology of yesterday to the comparatively sophisticated exploration, drilling, completion and production technology of the last two decades; and the aviation industry from the DC3 to the 747.

Methane technology is roughly where the aviation industry was in the 1930's. In its first 30 years the aviation industry accomplished, without revolutionary scientific breakthroughs, a productivity gain of roughly 100 times! -- comparing the DC3 compared to the 747. Thus, in its first few decades of an emerging new industry it increases the productivity of "in hand" technology and brings forth enormous new markets and unforeseen horizons just as we have experienced in the global development and proliferation of the aviation industry. There is no question that the methane industry is set to launch itself into equivalent productivity gains and begin to feel the effects of evolutionary and revolutionary improvements in methane technology as it expands into foreseen and unforeseen horizons in the increase of methane use.

The methane industry is set to experience the multiplying effect of the combination of technological improvements and productivity gains in exploration, drilling and production, pipelining and distribution, ocean transport, conversion to electricity (high efficiency combined-cycle gas turbines), and direct conversion of methane to competitively priced, clean liquid fuels with enormous implication for the future of the world's transportation sector. Simply stated, as methane technology improves, the amount of methane available as reserves and resources will increase exponentially.[10]

WITH ALL THE PROMISE AND BENEFITS OF AN EMERGING METHANE INDUSTRY AND EXPANDED NATURAL GAS USAGE, PRESENT EXPLORATION AND DEVELOPMENT HAS NEARLY STOPPED.

The pessimistic resource estimates of the past and rigid price regulation following the *Phillips* decision combined to create a self-fulfilling prophecy of natural gas shortages resulting in plant and school closings and other economic disruptions during the pre-N.G.P.A. winters of 1977 and 1978. Such shortages led directly into the post-N.G.P.A. gas drilling boom of 1980-82. These fears and perceptions, as exemplified by the "Club of Rome thinking," belief in finite resources, the "oil shocks" of the 1970's, and the "certainty of $100/bbl oil," drove gas prices beyond economic reality and caused runaway inflation in the gas drilling industry of over 30% per year and an equally large decline in efficiencies because of over-taxed use of equipment and inexperienced personnel. Thus, as demand was rapidly declining due to rising prices, "new found" elasticity, a deep recession and a shift away from heavy industry in the U.S., the resource base was being rapidly developed, leading to enormous increases in the producing capacity of domestic natural gas and what now is called a "glut." This sudden surplus of natural gas combined with rapidly diminished demand led to falling wellhead prices and *de facto* deregulation. The boom was over -- the bust is here and we are going through the severe economic pain related to 30 years of distortion from the regulation of an oil industry by-product and the inevitable effect of economic forces having overcome political resistance resulting in today's de facto deregulation of natural gas prices.

In 1984, economic recovery is well under way. Most of the "market disorders," which have been highly vocalized by certain segments of the industry and the cause, along with consumer reaction, to rapidly increasing prices in a proliferation of proposed legislation, have been resolved by powerful market forces leading to renegotiation of private sector gas contracts. In the gas fields of Texas, Oklahoma, and the entire Mid-Continent region, gas development activity has returned to pre-N.G.P.A. levels, limited no longer by wellhead prices but solely by the all powerful economic force of excess supply and reduced demand.

It is the lack of demand and clear national policy to release the shackles on the use of natural gas that will continue to hold gas drilling at dangerously low levels and inexorably lead us again to the self-fulfilling prophecies of shortage in the midst of an abundant domestic resource.

Let me clarify a little understood but significant fact of the emerging methane industry: independents are the production sector of the onshore non-associated methane industry, having continually been responsible for about 90% of onshore natural gas drilling. And it is the onshore lower 48 gas reserves that have borne the heavy economic cost of being substantially shut in while offshore production has flowed at near maximum levels. It has been the independents who have largely borne the cost of carrying unused inventory over the past two years. Yet, it is this onshore production that is so vitally necessary as the "swing supply" that varies with changes in demand and is most subjected to often out-dated, oil-related proration laws and rateable takes. It is our onshore lower 48 natural gas resources which are located near existing transportation and distribution systems that can be quickly developed by a highly responsive, non-bureaucratic independent sector which must continue to be available to meet new increments of domestic gas demand as they occur to prevent shortages and insure the ongoing supply/demand balance in the methane industry.

It is also the independents who, in the past, have expanded their drilling activity, not out of abundant cash flow available to the major oil companies, but by borrowing against newly established reserves or by raising public drilling funds that today are in "double trouble," and that fact is one of the primary reasons our nation faces renewed natural gas shortages.[11] The "double trouble" is the combination of severely reduced cash flow due to reduced gas demand and the apparent prejudice of our government's banking policy toward domestic natural gas lending which has not only drastically limited the availability of credit to overcome the reduction in cash flow but has also spilled over into the private sector financial markers thus reducing the availibility of public drilling funds.

Today's natural gas demand is limited in many ways: (1) increasing prices have brought new efficiencies and substantial conservation, (2) the U.S. economic motor has shifted away from the natural gas consumptive heavy industries of post-war industrialization, (3) unfortunate and untimely laws and regulations both federal and state, currently prohibit the use of natural gas, and (4) fear -- the fear of future shortages and their economic disruption, the fear of more legislation leading to more regulation (the "son of N.G.P.A."), the fear of incremental pricing and the totally unwarranted fear of a limited North American resources base necessary to provide our strategic planners and decision makers the necessary "comforts" upon which to base their long and short term decisions of capital expenditures.

Domestic energy lending and credit is today highly limited by the prejudicial attitude of U.S. bank examiners against domestic energy-related lending. Their policy is so stringent that the life blood of the independent sector is being squeezed away at the very time we, as a nation, have both the opportunity and ability to become energy secure through the development and use of our domestic natural gas.

For many in the independent sector of the natural gas industry, I must ask the question: Why is our nation's banking policy pro-foreign lending and significantly prejudiced against domestic energy lending? Why is our policy one of extending a helping hand to foreign producers and their economic associates while threatening the survival of many independent developers of domestic oil and gas? With an understanding of all the necessary concerns about the survival and strength of our national and international banking system, there is no question in my mind that the survival and strength of our independent sector is also of sufficient importance to the security of our national economy and our international relations that it too deserves equal consideration in the reformation of national banking policy.

THE UNITED STATES SHOULD NOW ADOPT A PRO-METHANE POLICY

Mr. Chairman, a pro-methane policy would:

1. Eliminate legislation and regulation prohibiting and limiting the use of natural gas which has:

   a. forced our utilities, without choice, to the economic disasters and capital-intensive inefficiencies of nuclear and coal use; and,

   b. forced our industrial sector away from domestic natural gas toward imported oil.

   With our new understanding of the abundance of the North American resource base as demonstrated by this hearing, it is no longer conscionable to hold legislation repealing the Fuel Use Act and incremental pricing provisions hostage to an "omnibus" natural gas bill or to legislation providing for "old" gas deregulation.

2. Review our banking policies in light of the implications of a domestic methane abundance on geopolitical and geostrategic decision-making and our domestic economic goals. An expanding methane industry could replace 4 million barrels of oil per day in the fixed industrial sector and thereby eliminate the need for U.S. oil imports and their impact on trade deficits.

3. Continue and accelerate the program toward further deregulation of the natural gas transportation and distribution systems, thus encouraging direct transactions between buyer and seller, the "spot market," a futures market and many other mechanisms which give instant market signals, thereby maximizing efficiency and supply/demand balance.

4. Provide tax incentives for the development of methane-fueled, integrated energy systems and the conversion of methane to clean liquid fuels which through the development of "in-hand" technology can meet most of this country's incremental need for increased energy in the most efficient and environmentally acceptable manner.

   The tens of billions of dollars in the Synfuels Program which our government is scheduled to spend on uneconomic and capital-intensive alternate energy systems should be shifted to the emerging methane industry. This would eliminate much of the near-term economic burden of these costs while securing the near-term economic gains of more efficient use of domestic energy capital and capturing the near term national economic benefits resulting from reduced oil imports and increased domestic energy expenditures and production.

5. End the Congressional war over natural gas pricing[12] which has for 30 years bogged us down in the political trenches of "liberal" versus "conservative" and "regulator" versus "free marketer." We must recognize that our democracy is the best system of modern government and, as Bismarck said, "If you like laws and sausages, you should never watch either being made." But, whether "legislation" or "sausage," the N.G.P.A. is the best legislation that could be accomplished within our free enterprise democracy and the political realities of today's America. Therefore, let it run its course, and let us rejoice in the political peace of de facto deregulation and the reality of market forces which now necessitate that the industry solve its own problems or go broke!

Such pro-methane policies, coupled with a public understanding of the emergence of a new, highly efficient, vertically-integrated, competitive natural gas industry, healthy and able to compete using as its source a domestic resource which will vie for market shares against an increasingly bureaucratic oil industry, an inefficient nuclear industry and an environmentally costly coal industry, will produce an economic freshness and a new hope for the expansion of an efficient methane-based energy system to assist in this nation's ongoing conversion from a heavy industry-based economy to the emerging service-oriented, information and technologically-based economy. Policies such as these will have vast and lasting national and international benefits.

Such pro-methane policies would foster the proliferation of an industry for development of efficient, benign, integrated energy infrastructures whose products could be essential to this nation's effectiveness in its responsibility for world leadership and our ability to effectively bring reductions in the geopolitical and geostrategic stresses caused by the multiple implications of today's global oil production and consumption patterns. The development of methane-based integrated energy systems for the "developing" economies will set the course toward the reduction of nuclear proliferation while rapidly increasing their productivity and standards of living.

Such pro-methane policies and the proliferation of their understanding will bring quick positive results to our national economy at a time when we face crushing deficits and their implication of renewed inflation.

By reducing the necessity to import large quantities of oil (which over the last decade has directly cost $500 billion and indirectly almost twice that amount to our economy), such a policy would thereby extend our economic recovery and add to our ability to handle our social responsibilities while providing for the increased defense of our country.

Mr. Chairman, I commend you and the members of this Committee for undertaking these hearings, so vital to the future of the United States, and I thank you for the opportunity to present my views.

FOOTNOTES

[1] Johnston, Robert R., "World Energy Developments 1981," American Association of Petroleum Geologists, vol. 66/11, November 1982, pp. 1709-1746.

[2] Gold, Thomas, "Terrestrial Sources of Carbon and Earthquake Outgassing," Journal of Petroleum Geology, 1, 3, 1979, pp. 3-19.

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[3] Rand - R. Nehring with E. R. Van Driest II, The Discovery of Significant Oil and Gas Fields in the United States, R-26541/1-USGS/DOE, Rand Corp., January 1981.

Hubbert - M. K. Hubbert, "Techniques of Prediction as Applied to the Production of Oil and Gas," in Oil and Gas Supply Modeling, S.I. Gass (ed.), National Bureau of Standards Special Publication 631, May 1982.

Zareski - Statement of Gordon K. Zareski, Chief, Planning and Development Division, Bureau of Natural Gas, Federal Power Commission, "Long Term Prospects for U.S. Gas Supply." Hearings before the Subcommittee on Energy and Power of the Committee on Interstate and Foreign Commerce, U.S. House of Representatives, January 27, 1976.

[4] Potential Gas Committee - Potential Gas Agency, Potential Supply of Natural Gas in the United States (as of December 31, 1982), Colorado School of Mines, June 1983.

Institute of Gas Technology - Parent, Joseph D., A Survey of United States and Total World Production, Proved Reserves, and Remaining Recoverable Resources of Fossil Fuels and Uranium, IGT, 1983.

Gas Research Institute - Woods, Thomas J. and Vidas, E. Harry, "The GRI Hydrocarbon Model: The Structure, Results, and Sensitivities of the Model in its Initial Form," GRI, May 1983.

USGS - G. L. Dolton, et al., "Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States," U.S. Geological Survey Circular 860, 1981.

[5] Office of Technology Assessment, U.S. Natural Gas Availability, September 1983, p. 48.

FOOTNOTES (CONTINUED)

[6] OTA, Op. Cit., p. 53, Table 13 - Historical Record: Number of New Gas Field (emphasis added) Discoveries Proved After Six Years To Be Of Significant Size.

[7] Dwight's - Energydata describes the Anadarko Basin as all of District 10 excluding Panhandle, Red Cave and Hugoton fields and twenty counties in Western Oklahoma.

[8] Samuelson, Robert J., "Economic Perspective; Merger Debate Reeks of Fuzzy Thinking," Washington Post, March 24, 1984.

[9] Oppenheimer, Ernest J., "A Call for Higher Taxes on Gasoline," New York Times, April 1, 1984, paragraph 2. "Between 1973 and 1984 this country paid about $500 billion for oil imports. According to studies prepared by Prof. Rod Lemon for the Institute of Gas Technology in Chicago, the hidden costs of imported oil, including adverse effects on the trade balance, domestic employment and output, inflation and military expenditures to protect vulnerable supply lines, more than double the direct costs. On that basis, the total costs to the economy of oil imports exceeded $1 trillion during the past decade."

[10] Osborne, David, The Atlantic Monthly, "America's Plentiful Energy Resource," March 1984, pp. 86-102.

[11] Merrill Lynch, Natural Gas Monthly, March 1984, pp. 4-6.

[12] Merrill Lynch, Natural Gas Monthly, April 1984, pp. 1-5.

APPENDIX

A

ASPEN INSTITUTE WORKSHOP

on

"R&D PRIORITIES AND THE GAS ENERGY OPTION"

Aspen, Colorado - June 25-29, 1978

Presentation to the panel on "Future of Conventional U.S. Natural Gas Supplies -- Quantification of conventional U.S. natural gas reserves and resources as a function of geographical location, depth and wellhead price; supply elasticity models and impact of regulatory policy."

by

ROBERT A. HEFNER III

Managing Partner, The GHK Companies

"THE FUTURE FOR CONVENTIONAL U.S. NATURAL GAS SUPPLY"

I am very optimistic about the future of conventional U.S. natural gas supplies. I predict that by the year 2000, barring further government interference, the U.S. will produce 35 trillion cubic feet of conventional natural gas per year. I am one of the few who project the strong probability of not only maintaining current natural gas production but increasing production significantly.

The difference between my projection of 35 trillion cubic feet of annual natural gas production by the year 2000 and most accepted projections is the equivalent of 10,000,000 barrels of oil per day -- the difference in whether or not the United States has a real, environmentally benign, opportunity to once again become energy self sufficient.

Predicting gas production of 35 trillion cubic feet by the year 2000 requires a belief in a much larger natural gas resource base than is generally estimated. Most "authoritative" and generally accepted projections forecast natural gas providing only 10 to 15 trillion cubic feet by the year 2000. These lower projections of achievable gas production are based on resource estimates which I believe are unrealistically conservative, emanating from years of extreme "regulatory distortion" and a view "through the window of oil."

Gas Resource Projection Bias Through the Window of Oil:

Our company's (GHK) mean estimate for deep gas resources below 15,000 feet within the Anadarko Basin ~~(Attachment I)~~ of western Oklahoma and the Texas Panhandle is 216 trillion cubic feet, while Exxon has projected that all depths within the entire "inland U.S." hold only 186 trillion cubic feet. Obviously, these projections are mutually exclusive and, therefore, one must critically examine the basis for such differences.

I have publicly questioned the Exxon estimate and I have corresponded and spoken with the person responsible for the project. He informed me that Exxon had 150 of its geologists working on various basins, and that the estimates submitted to the company headquarters in Houston by these local geologists were overly optimistic. In the final analysis, all estimates were revised downward out of the company's "worldwide experience" to present a more conservative picture. I believe that estimates made by those who have gained practical experience in individual gas provinces are more realistic and should be regarded with the highest level of confidence. Exxon was showing its bias for or understanding of oil by its unrealistically low "inland" estimate. Exxon's estimate of 186 TCF may, in fact, be simply a good estimate of remaining associated natural gas![1]

If one examines closely the so called "authoritative" projections of natural gas resources, one finds that most of them have been made by major oil companies whose geologists and economists understand oil and view natural gas as a by-product of oil exploration.

Throughout most of the history of the oil industry at least 95% of the deployment of risk capital by major oil companies has been made following an economic analysis based on the wellhead price of oil; the wellhead price of gas had little impact on the decision to risk capital.

Natural gas is different than oil in many ways. For example, natural gas is pervasive in all sediments and oil is trapped in unique accumulations. In the Anadarko Basin, you don't drill a dry hole, you just drill one that is uneconomical. Every hole drilled in the Anadarko will produce some natural gas. Natural gas accumulates in stratigraphic traps that are not readily identified by seismic exploration techniques used by oil companies to locate the type of structures necessary for oil accumulation. The successful development of onshore seismic "bright spot" technology is yet to come.

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[1] This also applies to forecasts by Mobil-Moody, and especially King Hubbert. ~~(See Attachment II)~~

Therefore, I believe that most of the projections made by the major oil companies, oil geologists and oil economists are essentially projections of what the future holds in associated natural gas. As a group, the major oil companies have never been in the business of taking large capital risks directed toward exploration for onshore non-associated natural gas. Since the early 1960's, the major oil companies have directed only about 5% of their total capital and exploration budgets toward onshore lower 48 gas development. For these reasons, I don't think the major oil companies, their geologists or economists (when taken as a group) have the real experience or understanding of many of the geological, technological, political and economic differences between non-associated natural gas and gas associated with oil production. Natural gas is its own animal. We must separate our thinking about gas reserves from many biases emanating from three generations of oil thinking. Methane exploration and production must no longer be viewed through the window of oil.

Gas Resource Projection Bias through the Distortion of Regulation:

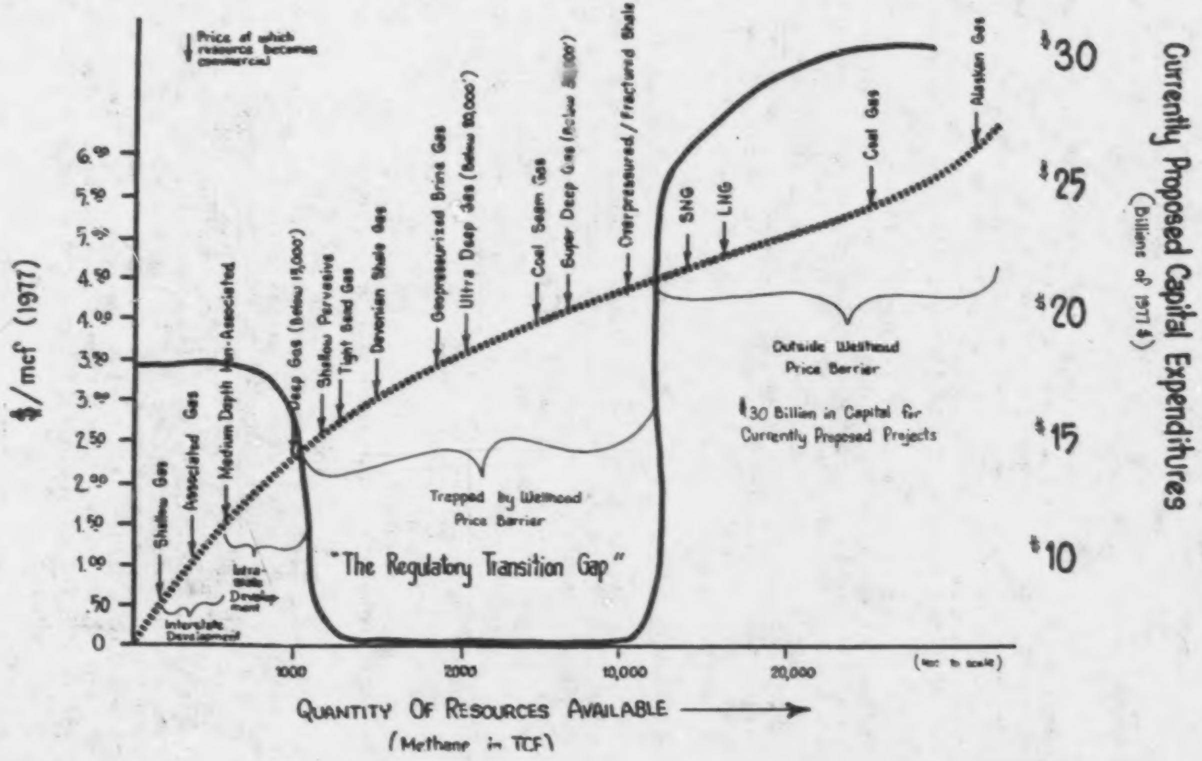
Twenty-five years of regulation has not only distorted natural gas supply and demand, it has distorted the corporate direction of the entire natural gas industry leading to biases resulting from corporate momentum and focus of corporate resources on various highly capital intensive projects outside the barriers of wellhead price ceilings. Instead of a natural transition from the production of higher and higher cost natural gas toward high cost alternatives such as LNG and coal gas, regulation has caused the industry to be marketing cheap natural gas and preparing through huge capital intensive projects to replace it with high cost alternatives; thus creating what I call the "Regulatory Transition Gap" (Figure 1). I am getting somewhat ahead of myself because I address regulation specifically later in my presentation; however, I must continue to stress that one cannot speak of the bias of natural gas resource estimates without understanding regulatory distortion of corporate planning and capital investment.

Let me be specific so you will understand exactly what I mean by "regulatory distortion of corporate planning and capital investment". I have had a running public debate with El Paso Natural Gas Company because it presents such a good example of the recent trend in the natural gas pipeline industry.

El Paso has committed the majority of its near-term future to LNG. It has invested more than a billion dollars in a fleet of LNG tankers and has tied up or spent over $100 million on various LNG projects that may never come to fruition. This commitment to LNG, all based on the "fact" that there are not sufficient natural gas supplies to meet U.S. demand resulted in El Paso's debt reaching $3 for each $1 of equity and a 1977 write-off of $21 million on the abandonment of its Alaskan LNG project. With the comparitive magnitude of these commitments, it is easy to see why its exploration efforts have received little attention from top

FIGURE ONE

REGULATORY DISTORTION OF CAPITAL EXPENDITURES



management and why the exploration budgets are relatively small. I believe this understanding of the focus of El Paso's resources explain the biases that built up over the years within a single company or an industry and is a good example of corporate direction toward large high-cost capital intensive projects creating a corporate or industry momentum away from natural gas.

Again, it was this belief by many in El Paso that we were "running out" of natural gas that led El Paso to contract with Sohio to convert its empty gas line to a crude oil pipeline and testify to the Federal Energy Regulatory Commission and the State of California that there was "no possibility" of securing sufficient new gas in its traditional supply areas to fill that line and meet the demands of the high gas consuming west coast area.

We at GHK totally refute the idea of "no possibility" of sufficient supplies by pointing to El Paso's expenditure totalling about $150 million over the last few years in the Anadarko (a small amount when compared to its $1.5 billion LNG project). This expenditure has already provided El Paso with about 200 million cubic feet per day of new gas production. In fact, we are now having to cut back gas production or sell to other pipelines in some parts of western Oklahoma because El Paso's pipeline is full and in the process of being looped!

Gas Resource Projection Bias through Lack of Experience

Natural gas pipeline company geologists and engineers are often the most pessimistic resource estimators because their experience has not been in exploration. Throughout the history of the pipeline industry until recently, there has always been an ample supply of natural gas; therefore, the few geologists who worked for the pipelines throughout these years were basically "production geologists" who were responsible for forecasting production from proven reserves and for conservatively estimating proven reserves for use by regulatory agencies and bankers. These "experts" gained little experience in exploration but are often looked to by laymen and government for "authoritative" future resource (exploration assessment) projections.

By recognizing the biases and limitations of the major oil companies and the natural gas pipeline companies in estimating remaining onshore non-associated gas resources, we find that most "authoritative" projections of natural gas reserves have been made by "experts" not actually in the business of exploring for onshore natural gas and, therefore, must be considered within the limits of their view. In contrast, we believe that the GHK projections of the remaining natural gas resources in the Anadarko Basin are realistic, even though they are comparatively large. We believe that estimates of remaining gas for the Deep Anadarko made by Exxon, Shell, Mobil-Moody or King Hubbert should have no more value than estimates made by GHK for offshore Atlantic where we have neither data nor experience.

Once a company capitalizes its belief, no matter how distorted, with billions of dollars (whether invented in offshore exploration or LNG tankers), it becomes pragmatically necessary and in the best interest of its stockholders to pursue that course to make the best possible return on its newly invested capital. Thus, "regulatory distortion" always leads to the inefficient deployment of capital which simultaneously lowers productivity and increases inflation.

"QUANTIFICATION OF CONVENTIONAL U.S. NATURAL GAS RESERVES AND RESOURCES AS A FUNCTION OF GEOGRAPHICAL LOCATION, DEPTH AND WELLHEAD PRICE"

Quantifying conventional natural gas is properly performed as a function of geographical location, depth and wellhead price. But again I am unable to quantify resources without addressing the impact of regulation on prices and capital formation. I must stress that the GHK estimates of the gas resources within the Anadarko Basin are based on (1) the current natural gas compromise or similar circumstances of economic and political certainty, (2) recent technological breakthroughs and (3) the continued extension of "in hand" technology for maximum production of deep and "ultra-deep" gas potential.

The GHK estimates for the Anadarko Basin are:

	Low	High	Mean
Shallow (0-15,000')	20 TCF	40 TCF	30 TCF
Deep & Ultra-Deep (15,000-30,000')	60	300	180
Super Deep (30,000-40,000')	12	60	36
Total	92	400	246

The most significant recent technological breakthrough for the production of deep gas resources is the development of a new proppant material used in fracturing deep gas wells. The proppant is made from bauxite and can withstand three to five times the compressive loading of conventional proppants without being crushed by the weight of the overburden. GHK was the first company to use this material for large, deep, high pressure fracturing in the Anadarko Basin. Many of our deep gas wells have initially demonstrated very low relative permeability (production capacity) due to damage to the reservoir during drilling and completion. We have recently been successful in increasing production capacity from one and one-half million cubic feet of gas per day to flow rates of more than 20 million cubic feet a day. Increased production rates significantly improve cash flow from these gas wells and, of course, both the improved economics and the ability to access more reservoir rock mean that in the long run more gas will ultimately be produced.

In addition to these recent technological breakthroughs, we have extended conventional drilling technology to greater and greater depths. GHK and Lone Star were partners in the deepest hole ever drilled in the world reaching a total depth of 31,441 feet. This venture was not only the world's depth record but, more important, for the first time allowed predictions of the existence of methane to depths of more than 40,000 feet ~~(See Attachment III)~~.

In the past, many petroleum scientists seriously questioned the existence of methane at these depths, believing that due to pressure and temperature the methane would be essentially "cooked" away. However, proving the existence of methane and ethane at 31,441 feet along with the vitrinite profile[2] from the well demands the projection of methane to depths beyond 40,000 feet. In addition, drilling contractors (Parker and Loffland Brothers) now assure me that they have the technological capability to drill 40,000 or even 50,000 feet. In the past, the limiting factor has been the ability of conventional steel tubular goods to withstand the temperature, pressure and corrosion from various gases that occur at great depths; now by using alloys developed for space technology, we have "in hand" the ability to overcome these tubular steel drilling and production limitations. These facts significantly impact onshore resource projections because all estimates for onshore natural gas stop at 30,000 feet which has up until now been considered the approximate limits of drilling technology and methane recovery.

Therefore, the combination of (1) the strong possibility of methane production from depths below 40,000 feet, (2) the ability to drill to depths beyond 40,000 feet (3) the ability to improve deep well completions using bauxite fracturing techniques and (4) the ability to produce highly corrosive gas through tubes made from non-corrosive alloys; all add significantly to our increasing levels of confidence in deep gas resource projections. At the next meeting of the Potential Gas Committee, we will be armed with new reinforcement for GHK's large Deep Anadarko Basin resource estimates!

In order to keep perspective, I want to point out that the Anadarko Basin is one of the two largest proven gas provinces in North America; the other is the Gulf Coast. There remains more than 76,000 cubic miles of undrilled sediments in the Greater Anadarko Basin, and it's all gas filled. That compares with 60,000 cubic miles of sediments in the Georges Bank Basin which we know very little about including whether or not it contains any hydrocarbons.

In the Deep Anadarko, only one percent by volume of the 22,000 cubic miles of sediments below 15,000 feet and above 40,000 feet have thus far been drilled. That one percent contains ultimate proven reserves of three trillion cubic feet of gas. Some argue persuasively that one cannot make a straight line projection of 300 TCF from this small one percent sample of drilling, holding that the largest fields are usually found first. However, one must consider that this early exploration resulted in "vintage" production with an average wellhead price of less than $1.00 per mcf. So, as in all natural gas projections, we must be wary of economic distortion and determine, if we can, how much more than 3 TCF of gas that same one percent volume of sediments might produce at a price of $3 or $4 per mcf combined with today's technology.

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[2] Vitrinite particles occurring in the kerogen of drilling cuttings were analyzed as to their reflectance capabilities. The higher reflectance values indicate higher levels of maturation with the deepest measured values still occurring within the range of gas condensate generation. Since the thermal alternation of vitrinite behaves as a linear function between any two vailid points, projections were made to estimate the lower limit for potential methane accumulation below 40,000 feet.

In order to prepare our GHK resource estimates for the Anadarko, we used the vast amount of geologic and engineering data available from the 60,000 producing, abandoned and dry wells in the province along with our own advantage of significant proprietory information (over 6,000 miles of modern seismic data and more than 100 man years of interpretation and integration into our geologic and engineering data base, by far the largest in the industry for the Deep Anadarko). Our preparation includes five different studies using techniques generally accepted for estimating potential gas resources. Each yielded similar results and that redundancy allows us a high level of confidence in our predictions.

Standing firmly behind our resource estimates, we at GHK believe that in the next twelve years at least 5,000 deep wells costing $16 billion in today's dollars will be drilled to develop the Anadarko Basin's deep gas resources. Annual production of deep gas in the Anadarko will reach a trillion or more by 1982 and then increase sharply. We have projected 4 to 5 trillion cubic feet by 1991, and it wouldn't surprise me if new deep production reached 8 trillion cubic feet by the year 2000.

"PRICES"

We have prepared many analyses of prices using FPC "770-A methodology" and assuming various depths, costs, finding rates and rates of return. To attain a 15% rate of return for onshore gas above 15,000 feet, using the national average finding rate of 300 mcf per foot drilled, a price near $2.00 per mcf plus inflation is needed. We at GHK believe that $2.00 will encourage shallow drilling and bring forth much of the remaining conventional shallow gas. Using the same parameters for wells drilled deeper than 15,000 feet and actual 1978 deep well costs, the price would have to be $4.67 per mcf. However, because in our experience deep wells have been more productive than the national average, we believe that prices in the range of $3.00 to $3.50 will allow sufficient return to attract billions of dollars of risk capital necessary to develop many trillions of cubic feet of new reserves. ~~(See Attachment IV)~~

These wellhead price calculations show why we support the natural gas compromise, because it makes good economic sense. The ceiling price on shallow development is high enough to encourage shallow drilling and production from "conventional" reservoirs. Meanwhile, under the compromise, deep gas and other high cost gas is deregulated within one year; which will allow sufficient political certainty for the formation of risk capital for the very high risks associated with deep drilling, and at the same time set in motion sufficient drilling to test our estimates of the deep resource base.

If our estimates are correct, we can continue to efficiently use the country's 100 billion dollar investment in existing distribution and consumption systems and avoid the necessity at this time of building a new $12 to $18 billion pipeline to Alaska. It is our position that each natural gas project should stand on its own commercial merit and be financed in the private sector without government subsidy or guarantees or consumer risks in the form of an "in all events tariff". That is not to say that various methane R&D projects should not go forward in combination with government and private industry as a backup to replace real shortages of natural gas should they occur.

Substantial increases in new gas production from vast deep resources can immediately begin to displace significant volumes of imported oil with domestic resources. I believe that by 1991 deep gas production from the Deep Anadarko province alone could eliminate the need for over 2 million barrels of oil per day and, at current prices, that is a 10 billion dollar annual reduction in our balance of payments deficit!

"ELASTICITY"

Of all major domestic energy resources, natural gas is the most responsive to changes in price. In Figure 2, I have modified the Department of Energy's MOPPS chart to indicate my view that even their high projections of gas resources are conservative. At about $2/mcf what I call the "shallow pervasive", that is, all that gas that produces very slowly in the Anadarko and other gas provinces, will start to become profitable to produce and will begin coming on stream. At $3.00 per mcf deep and other high cost gas will commence production. At prices beyond $4.50 per mcf ($1977) I think the curve will flatten and stretch somewhere beyond 1500 TCF of recoverable gas resources.

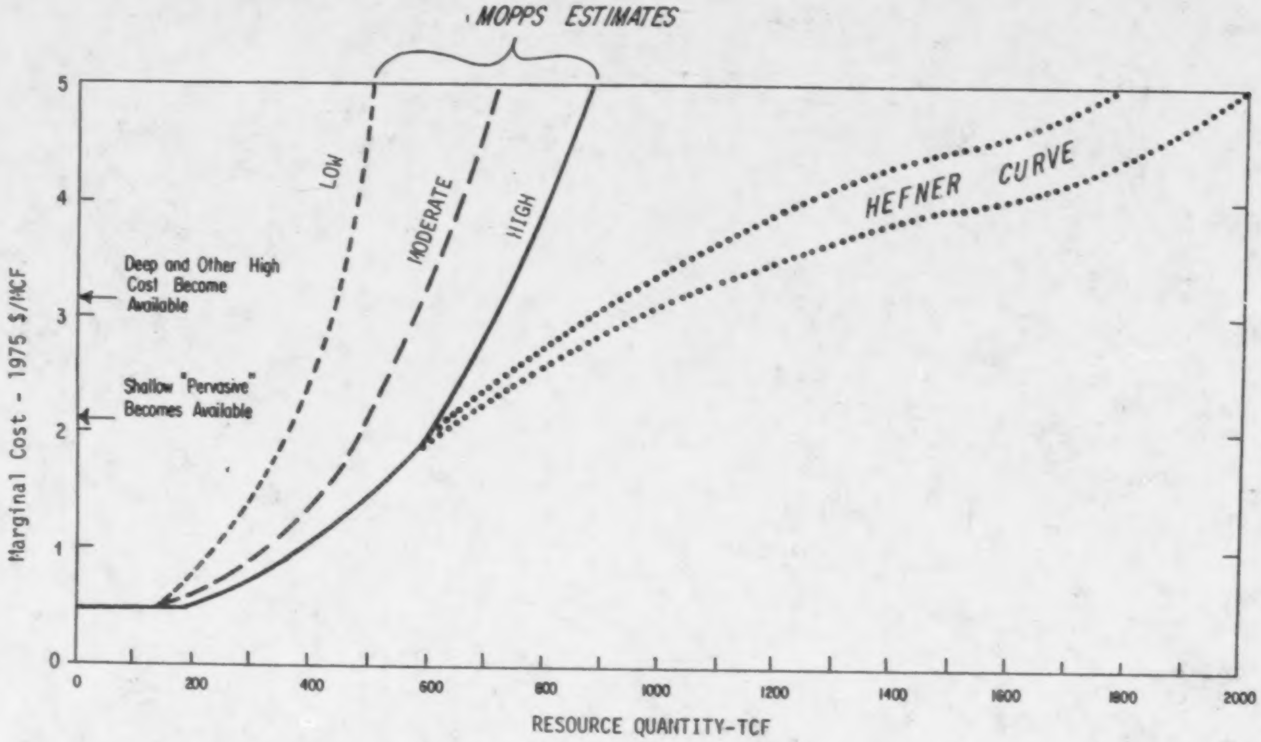
Dr. Don Murry, Director of the Bureau of Economic Research of the University of Oklahoma, has recently completed a study of the elasticity of natural gas in the Oklahoma intrastate market. Oklahoma's intrastate gas market is the freest market in the country because only 13% of the gas consumed in Oklahoma is delivered by interstate pipelines. The study found an elasticity of 1.6, which means that for every 1% increase in wellhead prices, production has increased by 1.6% (notwithstanding Zareski).

"THE IMPACT OF REGULATORY POLICY"

The impact of regulatory policy! The natural gas industry has undergone 24 years of capital and resource distortion through political manipulation. Regulatory policy will always have political

FIGURE TWO

GAS-ONSHORE AND OFFSHORE COST VS. RESOURCE QUANTITY*



*Status Market Oriented Program Planning Study (MOPPS)
Selected preliminary results drawn from December 1977 Review Draft, presented by Philip C. White, Fossil Energy Advisory Committee Meeting, Washington, D. C., January 12, 1978

overtones. It must, because it's a function of the government. And a democratic government will always take the short-term view because of the necessity of voter popularity. Therefore, if an error is made by any democratic government in the regulation of prices, it will always be made on the low side, in favor of the short-term interests of the consumer-voter. We've seen a clear example in natural gas price controls. Twenty-four years of natural gas regulation has provided this country with a clear and irrefutable example of regulatory error on the low side. This short-term or politically motivated policy has caused the consumption of vast amounts of our most environmentally attractive hydrocarbon for costs far below their replacement cost thereby (1) requiring future generations to subsidize today's standard of living, (2) creating macro-distortions of capital expenditures in the development of energy infrastructures and (3) giving an economic signal to the American consumer that promoted the blatant waste of precious national resources.

During my first meeting with Secretary Schlesinger, while in the middle of my explanation of why deep gas should be deregulated, he asked what would be the "macroeconomic effect of deregulation". I answered in terms of increased supply, reduced demand, etc. Now, reflecting on his question, I should have added the counterpoint that the macroeconomic certainty of regulation is the macroeconomic misapplication of capital and inefficient deployment of resources. The regulation of natural gas has clearly distorted the entire U.S. energy system. Dr. Schlesinger questioned me about the future, but I cannot assure you what might happen in the future. However, we can all look at the past and see clearly how our capital resources were misdirected by regulation, and how, in so many ways, that worked directly against our nation's economic interest. ~~(Attachment V)~~

Additionally, 24 years of natural gas regulation has rendered our natural gas economic data base useless for making any kind of meaningful future resource projections. Zareski's[3] projections about future gas availability is a classic example of trash-in/trash-out. I call it trash because he was using a 20 year data base that looked back at natural gas economics so distorted by federal price controls and the wellhead price of oil that there was no justification for his projections into the future. On March 21, 1977, Zareski presented his widely circulated statement to the subcommittee on Energy and Power in which he stated, "regardless of what happens to gas prices production will not substantially increase nor will it remain at present levels for a sustained period". He also said only about one-third of the lower 48 gas resource base remains to be discovered. His basis for these projections was the U.S. Geological Survey Circular 725 which relies on pre-1974 prices and does not reflect today's realities but contains all of the distortions of the past. Since that report, there has been a full order of magnitude increase in natural gas prices and much technological progress, all of which render his projections totally obsolete. The critical problem is that the Zareski analysis is still being used by some politicians as the "authoritative" basis for the argument that higher gas prices will not result in significant new supplies. On May 12, 1977, I presented a rebuttal to the Zareski statement which clearly and absolutely refutes all the bases for his projections. ~~(Attachment VI)~~

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[3] Gordon K. Zareski, Testimony before the Subcommittee on Energy and Power of the Committee on Interstate and Foreign Commerce, U. S. House of Representatives, March 24, 1977.

Further examples of capital distortions and the capricious use of our resources can be seen in the magnitude of dollars, political effort and brain power consumed in the "Washington War" over how best to bring natural gas from Prudhoe Bay, Alaska to the lower 48. During the past three or four years we have witnessed expenditures of $200 million[4] or more and who knows how many hundreds of thousands of man hours, in attempts to determine where the Alaskan gas pipeline should or shouldn't go with almost no regard to logical real economic feasibility. In my opinion, to commence a project in 1979 to spend $15 to $20 billion on any new pipeline to hook up only 25 trillion cubic feet of gas reserves is absurd, particularly when the transportation cost alone will be $4.00-$6.00 per mcf.

Another resource distortion is our present LNG investment. I'm not saying LNG will not be needed in this country, and I agree with the American Gas Association that LNG is much better than more imported oil, but I think we are committing to LNG projects long before it is economically justifiable without subsidies. As stated earlier, it is my position that El Paso's billion dollar investment in LNG tankers would be much better directed and more efficiently deployed in exploring the Deep Anadarko, where El Paso's expenditure over the past several years of only $150 million has already resulted in 200 million cubic feet per day of newly developed gas for its market. Compare these actual results to El Paso's projections for LNG, and you will see that exploration and development of lower 48 gas has been for El Paso a much more efficient way to deploy capital for acquisition of new and secure gas supplies. And when our current investment in the transportation and distribution system is added to this formula, there remains no comparison between the value to consumers of domestically produced natural gas delivered through existing systems and that of imported LNG.

I believe that without 24 years of regulation the natural gas industry would have experienced an ever increasing investment in the development of higher and higher cost natural gas, rather than relying on the effects of distorted supply and demand for distorted views of remaining resources thereby "necessitating" huge capital investments outside the regulatory barrior of wellhead price ceilings.[5]

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[4] An amount $50,000,000 more than that spent by El Paso on exploration in the Anadarko which has already brought forth a new supply of 200 million cubic feet of gas per day.

Natural gas price controls have distorted the whole energy infrastructure in the southwest. Lee White had a lot of nerve to come to a debate in Enid, Oklahoma, and cry out about Oklahoma's blatant waste of gas under boilers. We in Oklahoma built our energy industry to generate 90% of our electricity with natural gas because it was cheap. I don't know anyone else in the country (except possibly Joseph C. Swidler) who is more responsible for keeping the price of natural gas far below that of other sources (even coal) and thus sending the economic signal to American consumers that natural gas was in near infinite supply and should whenever possible replace all other energy sources (including solar) than Mr. Lee White himself during his term as Chairman of the Federal Power Commission and now as Chairman of the Consumer Federation of America's Energy Task Force. As I said, "regulatory error" will be made on the low (short-term voter) side and thus in the long term (as Mr. White has now recognized) result in waste.

Natural Gas: The Fuel of the Future

In conclusion, I predict annual natural gas production of 35 trillion cubic feet by the year 2000! Where did I get such an estimate? I simply started with the estimates made by the AGA and others of 15 to 20 trillion cubic feet in the year 2000, to be produced from more "traditional" supplies. Then because the resource estimates for the Anadarko Basin made by others have been so extremely conservative, I have projected this same "error" for other provinces. A combination of my intuitive feeling based on 20 years of practical experience in natural gas exploration and the result of many conversations with other "local experts" has led me to believe that the "Anadarko distortion" or error should apply to many areas. Therefore, I predict an additional five trillion cubic feet of deep gas production from southern Louisiana-Mississippi-Alabama, another five trillion cubic feet of deep production from the Overthrust Belt, and a plus factor from a few places we haven't even thought of. By adding this 10 TCF or more of additional production to my forecast of 5 to 8 TCF from the Anadarko, we arrive at 15 to 18 TCF per year over the more conventional estimates -- and there you have it, 35 trillion cubic feet in the year 2000! I think it's a possibility that must be considered in our national energy planning.

So, we at GHK confidently predict that natural gas is the fuel of the future. It makes me absolutely sick to my stomach to hear O'Leary say that "gas has had it". I think the time is here for people in government to be held accountable for their statements. The SEC sends people in the private sector to jail for official statements made with no more basis for reality than O'Leary's "gas has had it" statement! I am accountable. My accountability is that I have and will continue to risk all my personal assets and the assets of our companies upon these judgments. In addition, I'm laying my entire professional career on the line. I don't know who else is standing up pounding the table with that much at risk!

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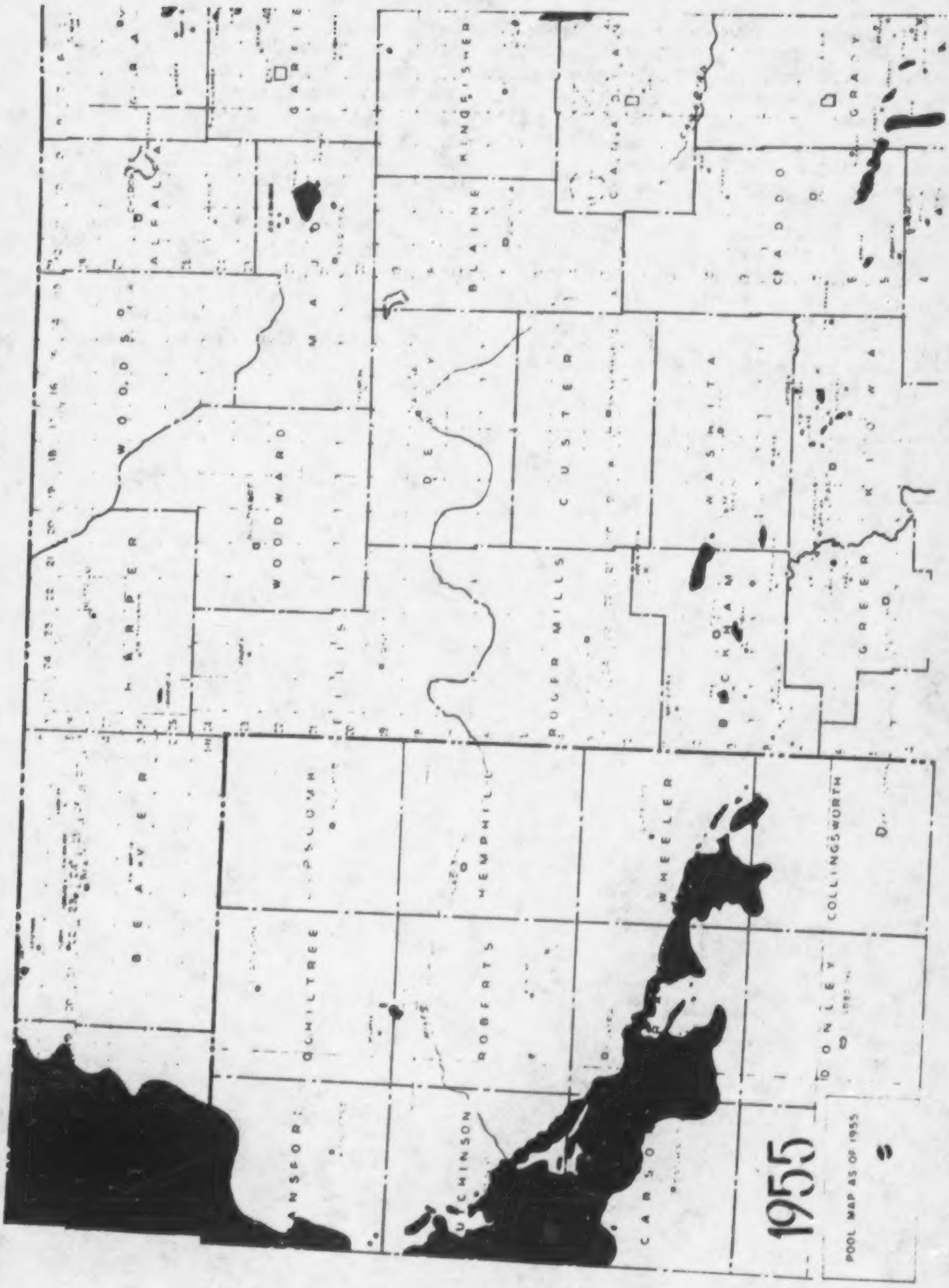
[5] Capital intensive projects outside the regulatory barrior of natural gas wellhead ceilings include: (1) pipeline and distribution company funding of major oil company offshore bids, (2) LNG, (3) SNG from liquids, and (4) SNG from coal.

Finally on the subject of risk, I must add that I understand well the risk of relying on the uncertainties of resource projections inherent in nature, the uncertainties of technology and the uncertainties of government actions, but I continue to remain "faithful" to the certainty of man's ability. I believe that in order for civilization to renew itself and achieve a higher quality of life, we must accept life with uncertainty and be led by those willing to accept accountability.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WASHITA
KIOWA
ELLIS
ROGER MILLS
BECKHAM
GREER
BEAVER
LIPSCOMB
OCHILTREE
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WHEELER
CARSON
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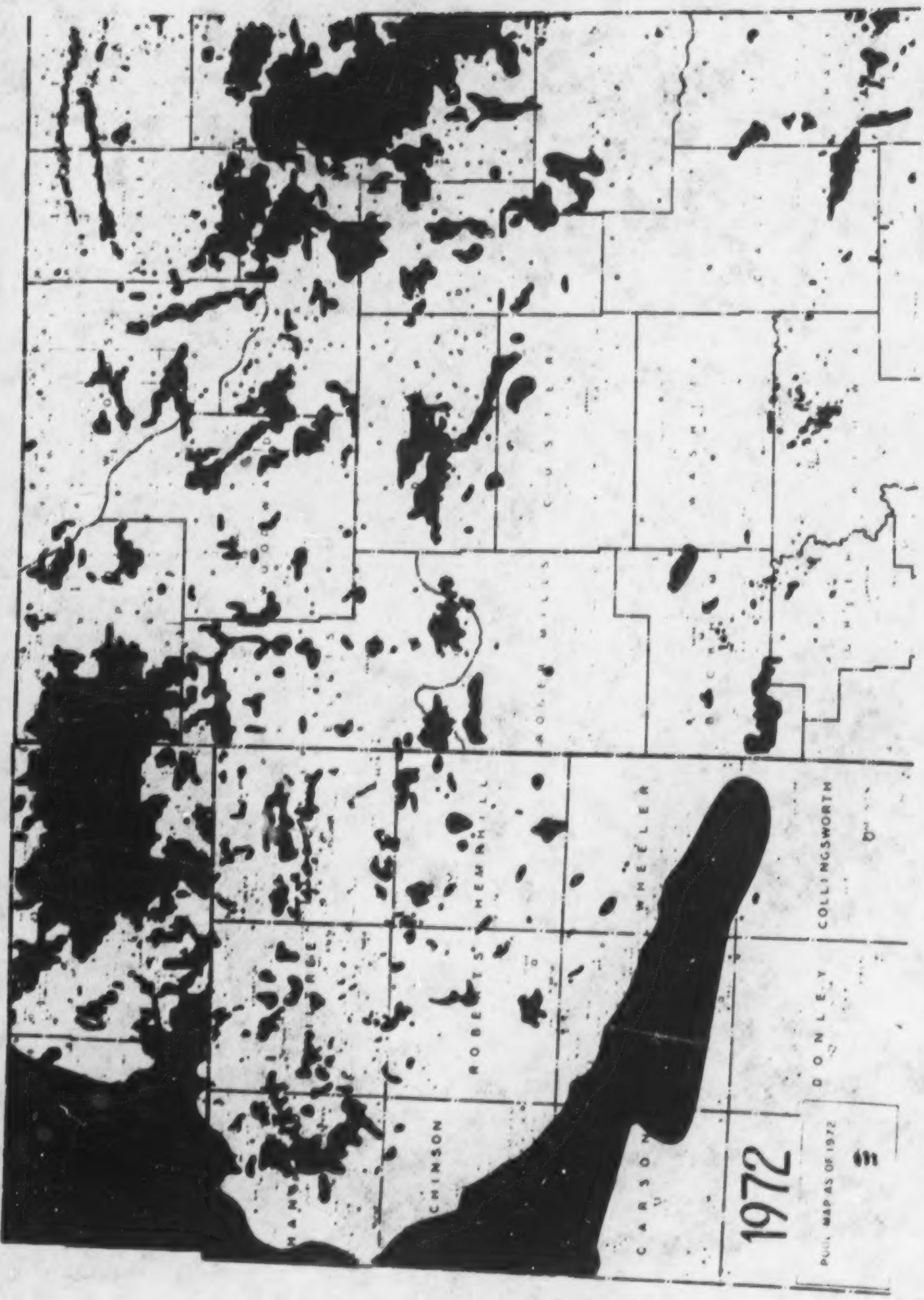
DONLEY
1955
POOL MAP AS OF 1955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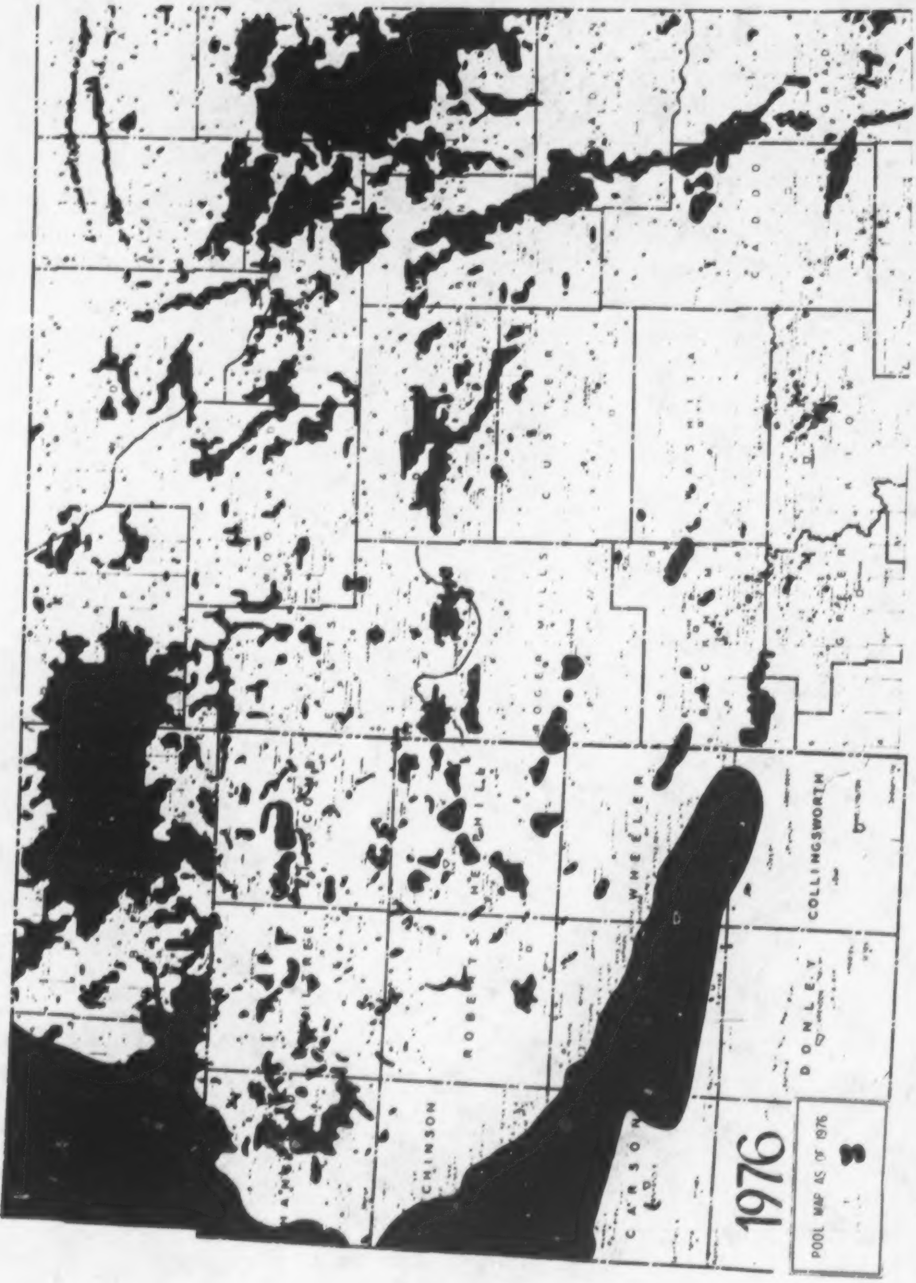
1972
MAP AS OF 1972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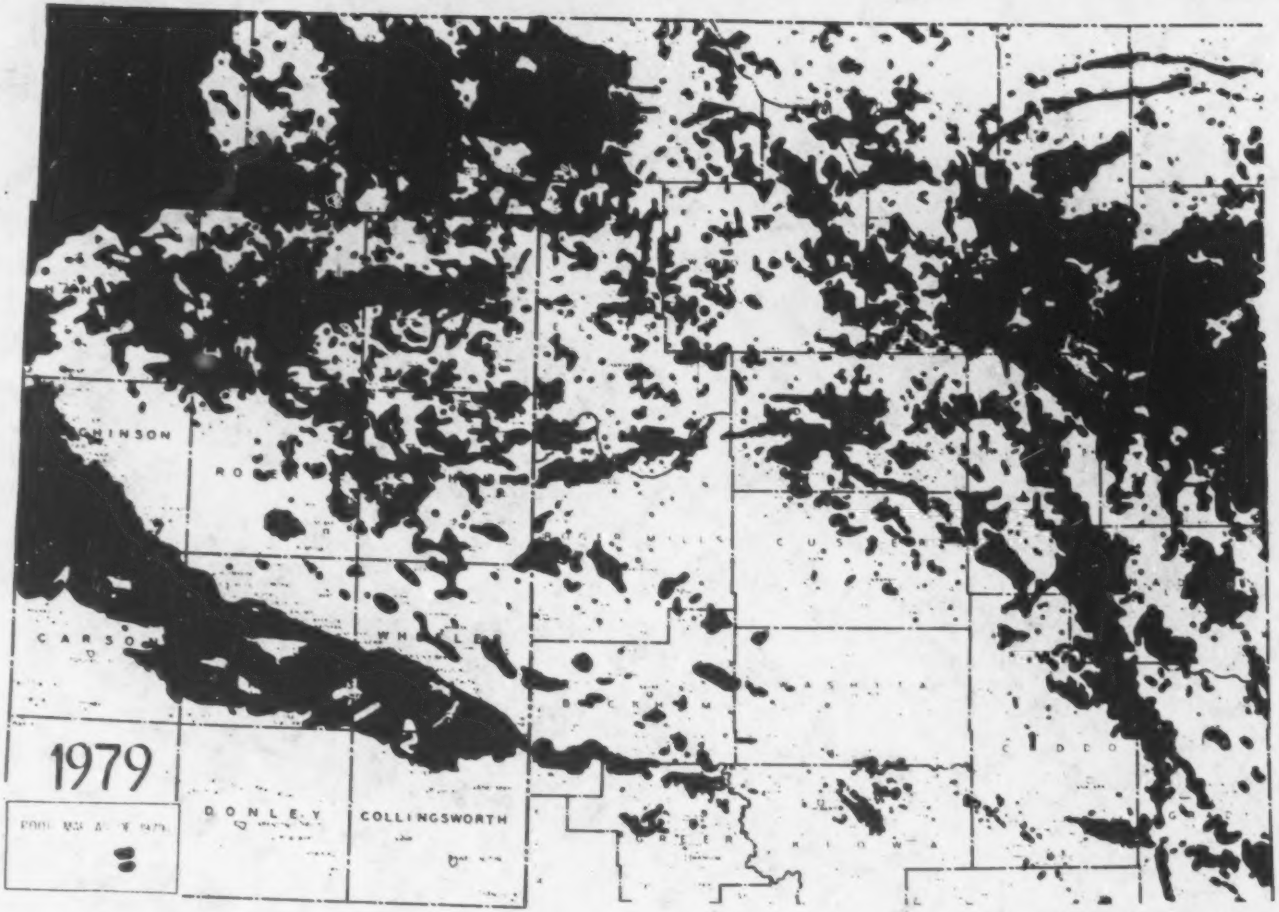
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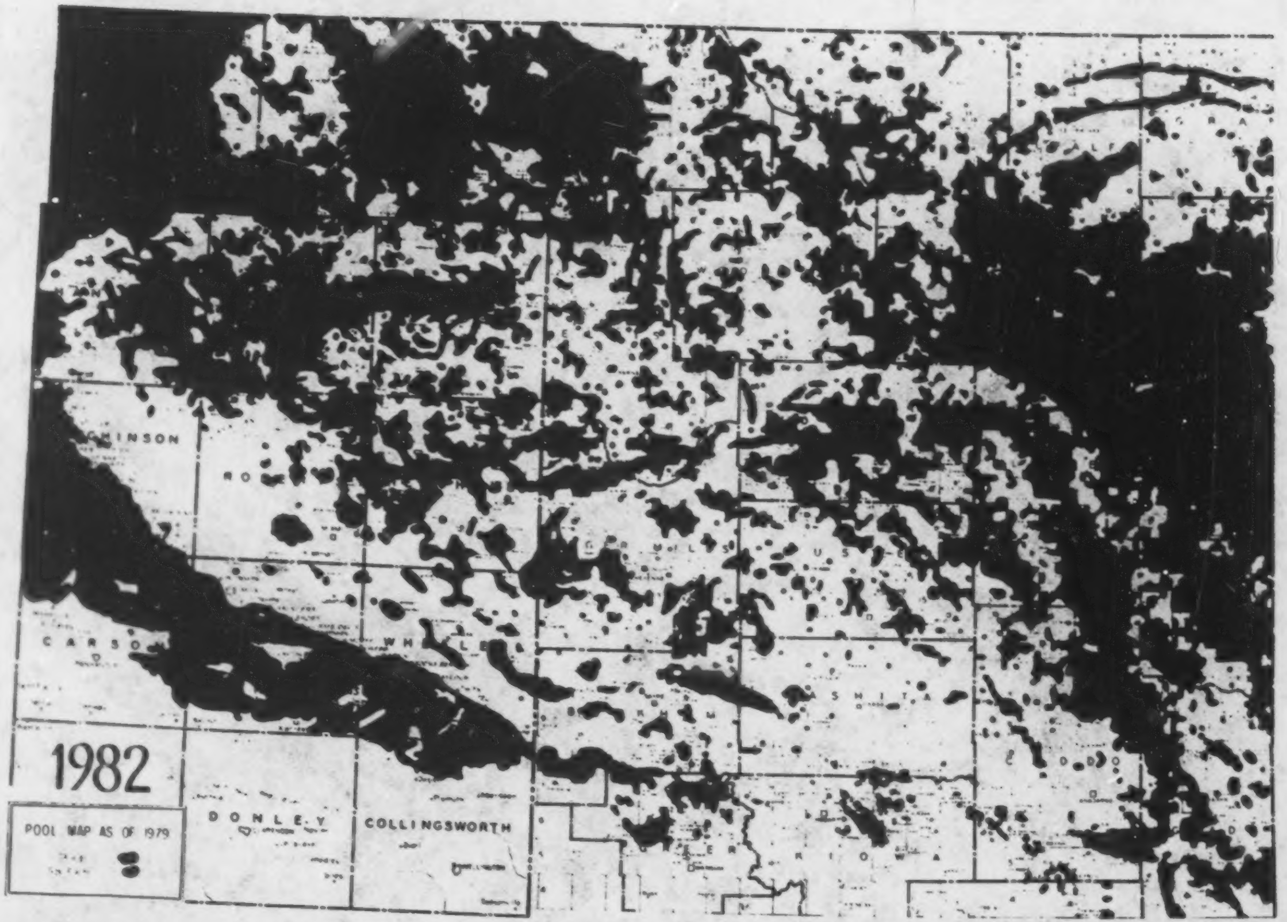
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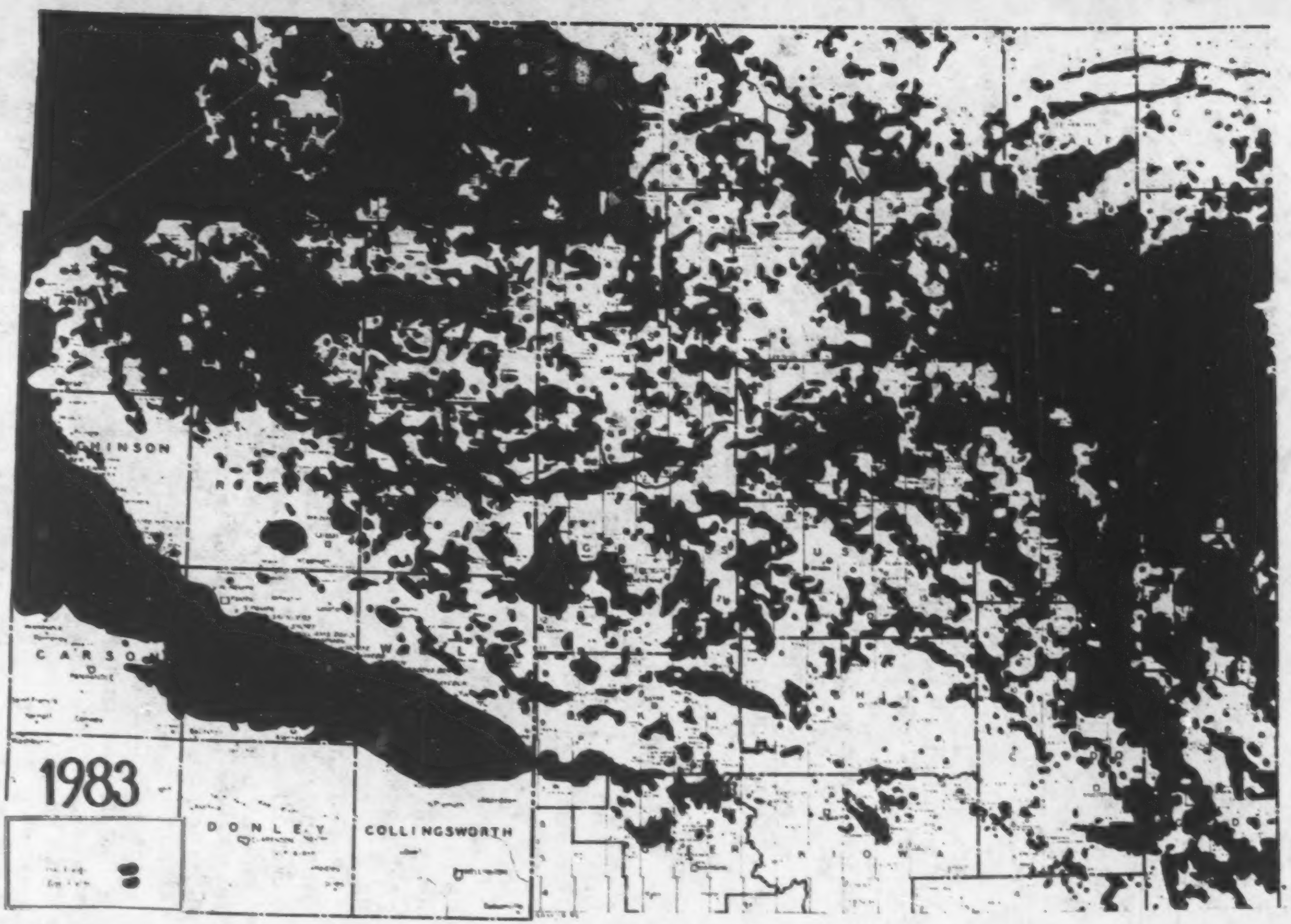
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Senator Murkowski. Thank you, Mr. Hefner, for that thought-provoking testimony, and your concluding remarks with regard to your own experiences, which you touched on briefly, and the climate which you claimed is one as perhaps as giving a rebirth, if you will, to the establishment of a methane industry.

The experiences in having to go and renegotiate these contracts is one that obviously you support in spite of the extraordinary difficulties associated with managing a company under those realities, I guess.

But, obviously, you support a free enterprise system and you're prepared to accept the realities that go with it.

Mr. Hefner. I do. The realities, certainly to the independent sector, is that if you don't have cash flow you're not going to be there. And so we're very responsive to the marketplace.

And, as I said, we're basically the onshore production sector of this emerging natural gas industry. So the independent sector has basically renegotiated all of its take-your-pick problems.

You know, they talk about the fly up, and the problem that's perceived also in 1985. I say let the NGP run it's course, the fly up won't come about because, again, the realities are you have got to sell your gas, and you can't sell it at a price higher than the market will accept. And we do have de facto regulation.

And if you want to use my chart for one other purpose here, the one with the orange line and all the blue lines and green lines going down, just turn it over, turn it upside down and the yellow line would represent the price of natural gas in reality, and all the blue and green lines would represent the estimates of fly-up, and be equally in error.

Senator Murkowski. Your particular approach is, I think, quite refreshing and stimulating in the application of the resource base and the fact that the industry today is emerging from the economics of oil, and it's your point of view that the emergence will be a split, if you will, and a self-determination as to the economics of gas.

Do you find yourself a voice in the dark, or do you have a significant number of followers that——

Mr. Hefner. Well, I have very few followers, certainly, in that conception in the major oil industry, or those companies that call themselves big—often big energy companies that have billions of dollars invested either in the technology and capital investments in oil, such as, refining or distribution, or in coal, or in nuclear.

But I think if you look to what's being written recently by many people in the financial markets, also by various economists who have studied utilities and natural gas over the years, you will find that more, and more, and more of them are coming to the idea that you have an emerging natural gas industry which is integrating itself into a vertically integrated, effectively competitive industry that never existed before.

And the existence of that industry—and we can see it every day restructing itself, in efficiences in the transportation sector that were never there before, distribution sector efficiencies, the production sector efficiencies that were never there before, and those efficiencies will allow us, I think, to continually take market shares away in this market in the United States, and certainly globally, from all these other sources of energy.

I believe what's happening is what happens every time an industry emerges. You have a proliferation of technological improvement and increasing productivity in the first decades.

If you take the beginning of the automobile industry, or just think of the airline industry, I think is a good example, from the DC-3 to the 747—which, by the way, I think was produced 20 years ago—but in those first 10 or 20 years in the aviation industry, we had a hundredfold increase gain in productivity, represented by the DC-3 to the 747. And there was not one scientific breakthrough in technology needed. It was inhand technology put to use in the emergence of that new industry that allowed that to happen. And I'm totally certain that will happen in the natural gas industry, and allow us to effectively compete in all these markets that people think we'll never compete in.

Senator MURKOWSKI. I have your comments, too, with reference to the balance of trade deficits, particularly with our neighbors, Japan, Korea, and to some extent Taiwan; all of which have substantial balance-of-payments deficits. I think Japan is about 21.6 billion, Korea is about 1.8 billion, and I believe Taiwan is about 6½ billion.

None of those countries have any degree of energy independence. They're totally dependent on exporting energy.

I believe, with the exception of a little coal, and a very small amount of natural gas, that no energy is being purchased from the United States, and some from Canada.

Mr. HEFNER. That's my understanding.

Senator MURKOWSKI. But as we address the balance of payments, we seem to want to reflect on the merits of beef and citrus fruits.

Somebody figured it out the other day, if Japan would lift the restrictions on beef and citrus fruits, we'd be talking about $500 million, to $1 billion over 5 years.

When you're looking at deficits and balance of payments in excess of $20 billion, you had better get onto something that has some meaningful and significant monetary impact. And energy is the most significant uniform thing we've got. We pride ourselves in negotiating occasionally for the sale of a nuclear powerplant, or negotiating for the sale of a particular item, but energy is continuous.

And I think if we're realistic about recognizing the growing deficit balance of payments that we have with our friendly allies, it's going to have to be reflected in energy purchases.

It's not appropriate that I make a speech out of it, but on the other hand, when you consider that we are their largest customer in each case of those three nations, you can begin to dictate some terms that you're going to allow that to continue.

And it seems to me an extraordinary opportunity for this country to begin to initiate some long-term purchases—or sales I should say, and those countries purchasing energy supplies from us.

And there are some other alternatives, and those are how you negotiate a deal.

But I do thank you very much for your testimony. It certainly brought, I think, some refreshing applications of ideas as to what our reserves actually are, and your emphasis particularly on the traditional gas coming from the economics of oil is something that I'm going to do a little thinking about and a little exploration on my own among my colleagues.

I wish you a good day, and thank you.

Mr. HEFNER. I thank you, and I will appreciate that thinking. I think it will be well founded. Thank you, sir.

Senator MURKOWSKI. Mr. Wheeler, I apologize to you. You certainly don't have to remain. It's been very kind of you to do so.

Mr. WHEELER. I appreciate that very much, Senator. If I could have the opportunity to make a remark or two, I would appreciate it.

Senator MURKOWSKI. Sure. I'm going to ask you to wait until after Mr. Jensen though.

Mr. WHEELER. Certainly.

Senator MURKOWSKI. Because in fairness to him, he's been either in need of stretching, or been very gracious in bearing with us.

Mr. Jensen is president of Jensen Associates.

We welcome you and look forward to your testimony.

STATEMENT OF JAMES T. JENSEN, PRESIDENT, JENSEN ASSOCIATES, INC.

Mr. JENSEN. Thank you, Senator.

In view of the hour, I'll try to be brief in my summary of the file testimony which you have.

The first point I'd like to make is that any discussion of natural gas supply, absent some context in which demand for that supply takes place, is incomplete. It's a little bit like the sound of one hand clapping.

And I think as we look at the pattern that we have seen over the last decade in the United States for natural gas and in the United States for all energy resources, and worldwide, the most conspicuous factor which stands out is the demand for energy is far lower than forecasters would have expected a decade ago.

The supply is really not much better than forecasts expected a decade ago. So we're talking about a situation in which it is demand that has created the present surpluses, not supply.

In that context several things have happened. First of all the lower cost energy resources which we were so worried about depleting a decade ago will last us a longer time than we thought they would a decade ago, and have postponed a period of time in which we have to look to higher cost resources and bring them on line.

Second, because it is a worldwide phenomenon, and because OPEC has become the world's swinging supplier of energy, it is backed up particularly heavily on OPEC, and the demand for OPEC oil is at levels that no one, I think, could have foreseen in 1974.

The effect of that really is that international oil prices at the moment are declining in real terms. And I think that for a number of years there is more of a possibility of a breakout on the downside than there is on the upside.

In an economy which is looking more and more to a selection of energy sources on the basis of economic considerations, that makes it very difficult to reach with high-cost energy sources now rather than wait and postpone them.

So I think we're really talking about that environment, and I think we have really not said that we don't need the high-cost energy sources, but we can wait a little bit longer before we have to make a move in that direction. And that's largely demand dicatated, not supply dictated.

There are really a number of ways in which you can measure supply. We have talked a lot today about resources. We have talked a lot about proved reserves.

I think it is important to emphasize again another measure, and that measure is production capacity or deliverability.

In the early 1970's we simply did not have the deliverability at the well head, regardless of proved reserves or resources, to meet all the demands for natural gas which everybody put on the system, and we had a shortage.

The moment, we have a system that is developed of contracting practices within the industry, in which take-or-pay levels to promote cash flow for the producers have been set at very, very high threshold levels of deliverability and the falloff and demand that was largely recession related in 1983, has pushed the industry into a surplus of deliverability and take or pay.

Now, that particular pattern, it's important to note, has taken place in a time when our reserves have really been declining.

The reserve-to-production ratio in 1971, when we were going into shortage, was 11.8 years. The reserve-to-production ratio in 1982, when we were in surplus, was 9.8 years.

All we are really saying is that the horizon of proved reserves that we have ahead of the deliverability has been deteriorating.

We have a surplus of deliverability at the moment. We have less assurance forward in time that that deliverability can be maintained than we had a decade ago.

Now, when we talk about the measures of what is in the ground, resources and proved reserves, I think the major issue that separates those two is that proved reserves, the budgets, the money to find and develop well-head production capability is largely behind us, it's largely been spent. Nobody has to say whether it's economic; it's gone.

The amount of money to be spent on creating production capacity out of the resource base is still in the mind's eye of the budgeters.

And whether or not they elect to put money in the ground and convert that resource base into proved reserves, and than into delivery capacity is something that only the market and the pattern of exploration, the way in which the industry develops will tell us.

I think it's dangerous to get too locked up into discussions of resource base, because until there's evidence that the industry is spending money on it, it's an economic abstraction.

Now, I would have to say also in the context of this hearing that at the moment I would have to say that the Prudhoe Bay reserves, although they are proved, are also an economic abstraction, because the transportation link which is needed to get those reserves to market has not been built.

If you cannot produce the gas at the wellhead because it's simply a resource that hasn't been found, or if you can't move it to market, it's in the same category.

However, the problem is somewhat different in this economic abstraction, because it does not depend on exploration, it depends upon justifying the transportation link.

It's an infrastructure problem. It's like building railroads transcontinental in the 1800's. Until the railroads are built you can't move things across the country.

You cannot bring gas from the Arctic areas down to the lower 48 States where markets exist, or you cannot move it to Japan.

I will comment briefly—I have a table that shows the resource estimates which you heard earlier today. And that table, which I'm not showing here on the board, simply shows the portion of the resources in the United States, Mexico, and Canada which would be considered as frontier—and by "frontier," I mean resources in which transportation is the major problem, not necessarily the exploration and development process.

Now, the interesting feature is that about 15 percent of the U.S. resources are in Alaska, where gas outlet, where gas transportation is a major factor, but 75 percent of the Canadian resource base is in the frontiers.

Now the frontiers, admittedly, vary from the Scotian Shelf, which is under negotiation right now, to the Arctic Island, which is an extremely difficult technical transportation problem.

So what we're really saying is an awful lot of those resources in Canada, or proved reserves, if they're found, are really not available to the market until somebody bites the bullet on transportation decisions and finds a linkage between the resource base and the ultimate marketplace.

I'm now going to move very briefly to the proved reserve estimate because, as I think I have indicated, it seems to me that proved reserves are the test that the industry is willing to spend money and come up with something; resources are the hope that they will.

We do a regular estimate on a worldwide basis of proved reserves, and try to separate out those reserves that are commercial and are likely to enter into trade from those that are in the figures, but we don't really know what's going to happen to them.

And this particular table, which is table 2 in the submission, is an adaptation of this approach essentially to the North American problem.

It shows the proved reserve figures as of the end of 1982, and they're the ones that you have seen this morning from several other sources, but it deducts, first of all, a category of frontier reserves.

Those are reserves at this point, like Prudhoe Bay, that are sitting there, but do not have a transportation outlet; and, therefore, are not presently commercial.

There are two other categories that we utilize. One is called deferred reserves, and it really means gas that is somehow or other associated with oil development.

The Mexican figure happens to be particularly large. And one of the reasons for that is the Chicatapeck field in Mexico, which is comparable in both oil and gas figures to Prudhoe Bay, really has yet to be developed.

And because the wells haven't been drilled—and it will really take an awful lot of them—that gas is really not available. It is also an economic abstraction.

Beyond economic reach refers to some small gas that is going to flare stack, very hard to commercialize. That's a Canadian term, and it makes sense in our context as well.

I have included the commitments to Japan, both from the Cooke Inlet and the reservation for the Dome Export project in Canada to Japan which may or may not go forward.

You have a subtotal then of available North American supply.

The next line is the national set-aside. Canada, in a sense, pioneered the concept of a national set-aside. They sit down and they have hearings at the National Energy Board periodically, and they say what are our forward requirements for natural gas, and what do we see by way of available proved reserves?

The last finding was in the Omnibus proceeding in 1982. They used a three-part test in that. One was 25 years of 1981 production. There was a present deliverability test and a future deliverability test.

But the essence of the Canadian decision is that they will not release reserves for export until they have satisfied themselves that they have covered their own requirements.

Now, the fall-off in demand for gas worldwide has also fallen off in Canada. In 1975, Canada was actively considering whether they would terminate exports to the United States because, at that point, they were looking at a demand for Canadian gas which would have swollen that set-aside figure.

Now, of course, with the fall-off in Canadian demand, there is a surplus of deliverability, and so the reserve figure is there.

But I think one has to recognize that always, Canada will look at the number and decide on protecting its own market first, and then will create exports to the United States.

We sit essentially behind Canada in that set-aside figure.

Mexico has never gone through a procedure of set-aside. We've had some discussions in some meetings we've had with the Mexicans. That's our estimate of what it is, and I think it's valid.

But the net effect is that by the time you get back down to the bottom, contracted reserves and available surplus, 83 percent of the proved reserves that would support U.S. demand today are in the United States. Only 14 percent are in Canada, and only 3 percent in Mexico.

Now, this is a calculation that will renew itself in time. I do not deny that. But it says that the size of the reserves at the top are misleading when you are considering what is available to cover U.S. needs.

Senator **Murkowski**. And you've excluded Alaska.

Mr. **Jensen**. I've not excluded Alaska. I've put it up top there with the frontier reserves.

Senator **Murkowski**. So it's less frontier reserves.

Mr. **Jensen**. It's frontier reserves. So at the moment it does not support demand in the lower 48 States.

Senator **Murkowski**. So it's not included in the——

Mr. **Jensen**. If we were to go into a situation like curtailment in the next year, the Alaskan reserves would do us no good, because they are not available to market at this time.

Now, I suppose the final conclusion that I come to is that the problem of the frontier—and that is very much—it's much more a Canadian problem than it is an American problem—is a problem of transportation links.

You've got to find some economic way of linking market with reserves. And if that economic way is not found, then those reserves will not move to market.

The ANGT project originally was conceived as a kind of cooperative project. The Dempster Lateral was viewed as tying into the Alaska pipeline project originally. And that would make a reach to the Canadian Arctic reserves, tie in with a reach to the American Arctic reserves.

I do not know what the economics would be of building the Dempster Lateral by itself. I suspect the proved reserves in the Mackenzie Delta at this point is probably too small to justify a separate line.

I would point out, just by way of illustration, the prebuilt portion of the Alaska pipeline in the lower 48 States—which in the Alaska context looks like petty cash, it's a small portion of the total—is the largest pipeline investment that has ever been built in the United States.

We are talking about massive expenditures to move gas, and, therefore, mistakes in the layout of design of the system are very costly in an environment in which the market is not prepared to pay high prices for gas.

So I think the bottom line which I have come to—and I'll terminate it very quickly—is that we have to be very careful that we do not fritter away Arctic reserves, and forever postpone the day when the ultimate transportation link has to be made.

I think someday it has to be made, and I would hate to see us nibble away at the reserves and create a situation in which it never could be done.

Thank you.

[The prepared statement of Mr. Jensen follows:]

Statement of
James T. Jensen
President
Jensen Associates, Inc.
Before
The Subcommittee on Energy Regulation
of the
Committee on Energy and Natural Resources
United States Senate
April 26, 1984

My name is James T. Jensen. I am President of Jensen Associates, Inc., a firm of consulting energy economists with offices in Boston, Washington and Geneva. From 1978 through 1981, we were the marketability consultants for the Alaska Natural Gas Transportation System. More recently, we have been active for a number of Canadian clients in reviewing the markets for Canadian gas in the United States and the implications of Canadian border pricing policy on those imports. We have also acted as consultants to the Office of Technology Assessment in its recent evaluation of conventional gas supply through the year 2000.

I have been asked to address the topic of North American natural gas reserves and resources. It is important to note at the outset that any discussion of natural gas supply which is divorced from an expectation of natural gas demand is by its very nature incomplete, rather like the sound of one hand clapping. We currently have a natural gas surplus--"the gas bubble." And yet, the gas bubble is far more attributable to a fall off in demand for natural gas than it is any fundamental improvement in gas supply. Demand for natural gas in 1983 was some 23 percent below the peak year of gas demand in this country of 1972. The fact that current expectations of gas demand are so much lower than earlier ones simply means that the lower cost conventional gas reserves will last a lot longer than we previously thought. By the same token, the day on which we will have to fit higher cost non-conventional gas and supplements into the supply mix has been postponed. The longer term problem of minimizing the cost to the economy of these higher cost supplies has not gone away, however.

Our own forecasts of demand foresee some recovery in 1984 from the depressed market levels of 1983 but then a very gentle decline in demand over the rest of the decade as residential and commercial demand remains about flat and the limited growth in high-value industrial applications is more than offset by an erosion of industrial and power generation boiler fuel. The implications of such a demand forecast are that a limited growth in imports and supplements can handle foreseeable demand without shortages even if one accepts--as we do--the view that production from conventional Lower 48 reserves will itself be declining over the period. A review of 20 Lower 48 gas supply forecasts in the recent Office of Technology Assessment supply study showed an average estimated decline of about 1.6 percent per year for the next decade. The flavor of my remarks on supply are in the context of a market which is not growing and will not make the kind of demand on gas supply which most forecasters anticipated five to ten years ago.

Supply may be measured in a number of different ways. Depending on the question at issue, one measure or another will assume greater importance. The Economics 101 supply/demand curve which has become so fashionable in the age of deregulation is a simple plot of price versus volume. It does not concern itself with the changes in these relationships over time, nor does it have any means of dealing with the problem of uncertainty. For the supply of a depletable resource such as natural gas, the time dimension and uncertainty are essential factors to be considered in both private sector investment decision making and in public policy.

The most immediate and probably least uncertain measure of supply is deliverability. When existing wells do not have the deliverability to supply enough gas to meet demand--as was the case in the early 1970s--physical shortage is the result. Because of the recent contracting practices of the gas industry which have tended to tie high contractual take-or-pay threshold levels to wellhead deliverability, the recent fall-off in demand has forced the pipelines into substantial short-term surplus--the gas bubble. The deliverability surplus is not necessarily directly linked to another important measure of supply--proved reserves. The ratio of reserves-to-production in 1971 when the industry was suffering shortages stood at 11.8. In 1982, with a substantial gas surplus the R/P ratio was only 9.8.

Whereas deliverability is the measure of near-term supply shortage or surplus, the measure of supply which attempts to quantify the distant and uncertain future is the estimate of the resource base. Conceptually, the natural gas resource base includes all of the gas in the earth's crust which is likely to be found and developed over the entire ultimate history of exploration. Estimating the size of the resource base is an exercise in applied expert judgment. No one can say with certainty that the gas is indeed there, let alone how much it will cost to find and develop and when it will become a part of available production capacity.

Proved reserves are the measure of what has been actually found and is thus capable of development and production. Explorationists commonly have some idea of the magnitude of a new discovery after the discovery well, but initial estimates are subject to a wide range of uncertainty until such time as the field is fully developed and put on production. Even during a field's productive life, reserve estimates frequently change as a result of new information about the way the reservoir behaves. It follows that proved reserve figures for the same fields can vary quite widely unless the estimators are given common ground rules on how to make the estimate. The practice in the United States has traditionally standardized on relatively conservative estimates of proved reserves but there is no guarantee that the proved reserve estimate in another country, such as in Mexico to use an example, is comparable to a proved reserve estimate in the United States. Thus, caution must be exercised in comparing figures across national boundary lines. Even in the United States, when the Energy Information Administration took over the job of reporting proved reserves from the American Gas Association, the overlapping data years of 1977 through 1979 show a consistently higher estimate from EIA than from AGA. That is not to say that the supply position was any better because EIA reported a larger number, but only that the procedures and standards used were different.

The concept of resource base is widely used in national policy making. Some supply forecasters rely heavily on resource base estimates as a part of their forecasts, while others tend to view the concept itself as sufficiently vague to be relatively impractical for short-term forecasting.

Since proved reserve and resource base estimates are both measuring gas which is contained in the earth's crust and potentially available for future production, there is frequently a tendency to confuse the two. They are really very different measures of supply. Proved reserves have already been found and largely developed. The exploration and development budgets required to develop commercial production at the wellhead are already largely spent. But since the money required to find and develop undiscovered resources has yet to be budgeted and will depend on prospective economics, resource figures are largely economic abstractions. The history of oil and gas exploration is replete with examples of exploration "plays" which fizzled out because some feature of the economics of the activity turned sour.

Whereas proved reserves figures usually represent gas which can be economically produced and marketed, while resource base figures are more abstract in a commercial sense, some proved gas reserves which are remote from markets may also be economic abstractions absent a viable transportation link to market. This is especially true of the frontier reserves of the Alaskan North Slope, or the Canadian Mackenzie Delta, Beaufort Sea, or Arctic Islands. Until such time as transportation links to the main North American market centers can be justified and built, those proved reserves --like the, as yet, undiscovered resources in the same areas--are largely useless in the context of North American gas supply and demand. The barriers to commercialization in the frontier areas are not reserves or resources, but rather transportation. It is thus a problem on infrastructure, somewhat akin to the building of the transcontinental railway system in the 1800s, rather than a problem in gas supply as such. The danger to ultimate use of this gas in North America is that a series of incremental reserve disposition decisions will be taken, which--however desirable in isolation--will erode the reserve base in a way that undermines the economies of scale of these costly transportation links.

For reference purposes in Table I, I have shown typical recent estimates of resource base for North America, including both the major supply areas as well as the Canadian and the U.S. frontier areas. Since resource base estimates tend to be made using probabilistic techniques, I have shown only representative base case estimates for different groups.

For the United States about 15 percent of the undiscovered resource estimate represents frontier area gas where transportation looms as a major problem. For Canada, the problem is much more acute since about 75 percent of the Canadian resource estimate is in frontier areas. The Canadian frontiers do vary in their economic accessibility. The sale of Venture field gas from the Scotian shelf is presently being negotiated, but transportation is likely to loom as a major obstacle to early commercial utilization of Newfoundland and Labrador shelf discoveries as well as the Canadian arctic area gas.

As originally conceived, access to U.S. North Slope gas through the Alaska Natural Gas Transportation System was to interact with Canadian gas supply planning in several ways. The routing made it possible at some point for easier Canadian access to Mackenzie Delta gas through the "Dempster Lateral." And greater confidence that such easier access to Canadian frontier gas could be integrated with the U.S. system was a factor in releasing some conventional Alberta reserves for export through the "Pre-build" systems. The present acute deliverability surplus in both U.S. and Canadian conventional area sources may have obscured the value of a coordinated transportation link between the North American arctic and the major markets to the south, but is has not destroyed its ultimate logic.

I have shown no Mexican frontier resources since none of the Mexican producing areas seems to require the major new transport link to market which the North American arctic appears to require. But it should be noted that as exploration in Mexico's Gulf of Campeche moves farther offshore, it will become increasingly costly to gather the associated gas and transport it to shore.

If a measure of uncertainty clouds the availability, the timing and the cost of undiscovered resources to U.S. markets, the disposition of proved reserves is much more certain. From Table I, it is important to note that the U.S. and Canadian proved reserves are heavily oriented towards non-associated gas, while the Mexican reserves are predominantly based on gas either dissolved in oil or in gas caps within oil fields. Production of oil well gas tends to be dictated by oil production considerations and thus it is very possible for the gas simply to be flared if there is no market outlet for it. In fact, nearly 25 percent of Mexican gas production is currently being flared. Most of this is in the Gulf of Campeche offshore and the Mexicans are in the process of investing in recovery and gathering facilities to commercialize this gas.

Another problem of oil well gas supply is that it may be unreliable if oil production falls. The Saudis, who spent some $20 billion on a Master Gas System to collect their various flared gas sources in the field, are now finding that they have insufficient gas to fuel many of their industrial facilities since oil production levels are very low. Balancing supply and demand is much simpler in a reserve mix with a high proportion of non-associated gas reserves as in Canada and the United States.

Table II provides an estimate of the present market commitment status of North American proved reserves. Although the proved reserves of gas in the frontier areas are included in the reserve figures, they do not have a commercial outlet and Table II deducts these frontier gas sources as not presently available.

Our firm makes worldwide estimates of natural gas availability as a basis for local economic growth and for international gas trade. We normally utilize a series of six categories of proved reserves. These have been adapted in Table II to show the potential gas available to the United States from existing proved reserves.

The category entitled "deferred reserves" primarily includes gas which is being reserved for oil recovery or production operations and is thus currently unavailable for market. The Mexican deferred reserve figure of 26.7 tcf is in recognition of the fact that the very large Mexican Chicontepec oil field--comparable in both oil and gas reserves to Prudhoe Bay--will require thousands of wells and many years to develop before the gas can ever be considered commercial.

A third category of reserves includes those which are too small or too remote to recover. Canada terms these "beyond economic reach" and I have used that terminology in Table II.

Most gas reserves are committed on contract to pipeline purchasers. The United States has committed a small quantity of reserves in the Cook Inlet area of Alaska to Japanese trade and the Canadians have authorized a project by Dome to ship gas from Western Canada to Japan, although this project is not certain. I have deducted those reserves from the North American availability.

Canada pioneered the concept of setting aside a portion of proved reserves to protect domestic markets before considering permits to export additional gas. The concept is increasingly being adopted by other countries. Periodically the National Energy Board will review the Canadian reserve position and using "Surplus Determination Procedures," determine how much gas can safely be licensed for additional export. While the procedures have varied somewhat over time, the latest Gas Export Omnibus Hearing in 1982 utilized three tests to determine if gas could be licensed. They were (1) a current Reserves Test, which requires 25 years of coverage of the current year's Canadian demand plus remaining authorized exports; (2) a Current Deliverability Test; and (3) a Future Deliverability Test.

In earlier years, the formulas approximated 30 years of Canadian requirements at existing levels, but now the reserve test is based on 25 years of reserves, excluding frontier, deferred and uneconomic reserves. It is important to note that the United States with a reserve-to-production ratio--in surplus--of less than 10 years is operating far less conservatively for our own requirements than is Canada for its requirements.

The gas industry in Mexico is in its infancy. At this point it is very difficult for the Mexicans to judge how much gas they want to utilize at home relative to what they wish to export. They have little experience with the exercise which has become common in Canada--determining the proper amount of gas to set aside for domestic use. In addition, the special problems of dealing with the inflexible associated gas production complicates the Mexican export policy decision still further. In Table II, I have shown an estimate of Mexican set-aside for illustration. The fact that the number is very similar to the Canadian is purely coincidental. The Mexican figure is based on thirty years of set-aside at the average expected level of demand between 1982 and 1990. This estimate, arrived at in a similar fashion to some earlier Canadian calculations, I have discussed privately with Mexican officials and believe that at this stage of development it is reasonable. One has to recognize that it might change but the fact that Mexico now seems much more interested in preserving gas for domestic use and exporting oil instead seems to confirm the general outlines of the calculation shown on Table II.

The resulting reserves potentially available to the U.S. market, whether explicitly contracted or simply surplus to the other commitments, are summarized at the bottom of Table II. U.S. reserves at 83 percent remain by far the most important. While Table II is a static year-end 1982 view of what is essentially a dynamic process, I would not expect the proportions to change materially for the next few years.

The U.S. has a substantial short-term gas surplus. Some observers in the industry believe that a near-term demand resurgence from recessionary levels, when combined with the fairly rapid decline in deliverability from relatively short-lived gas reserves, argues for an early return to a natural gas shortage. We do not share that view and do not believe that the shortages of the early 1970s are likely to reoccur for some period of time into the future.

Were the deliverability surplus to begin to dry up under the influence of reservoir decline rates, there is of course still some additional production capacity available from imported gas. Mexico is operating at 60 percent of permit volumes, albeit small, and Canada is operating at only 43 percent of the exports it has authorized to the United States. But the most important factor that distinguishes the market of the next few years from that which occurred in the early 1970s, in our view, is the emergence of market price competition between oil and gas and the question of what market share gas will capture.

We estimate that about 6 tcf of natural gas is now utilized in dual-fired boilers where the gas market share compared to oil is extremely high. In contrast with the early 1970s when gas was usually priced well below oil and many boiler fuel gas customers did not have oil-firing capability, this market can switch away from gas quite quickly when gas prices rise too high. This creates a kind of price buffer which inhibits the purchase of more expensive gas supply. But as this buffer gradually erodes, market clearing prices should rise relative to oil, and higher cost supplementary gas supply should again begin to be attractive.

Some of the new supplies have great potential. Tight sands in western United States, or even such things as geo-pressured methane may provide substantial additions to supply, but as with deep gas from some regions in the Lower 48, it is not clear what kind of a price will be required to bring forth the rate of reserve additions needed to sustain long-term demand. Movement at some point toward interest in the frontier areas of the U.S. and Canada, and greater interest in Mexico, is almost inevitable with the only real question being that of timing.

Canada at the moment is selling only 43 percent of the gas authorized for export to the United States and would love to increase the export level. But in the nature of the Canadian formula with its protection of Canadian demand first, the availability of Canadian gas is likely to be its highest and most certain in the nearer term. The existing permit authorizations using the Canadian formula in fact suggest a substantial drop in Canadian deliveries to the U.S. between 1990 and 1993. While Canadian shipments to the U.S., like U.S. production levels, are subject to constant renewal as new reserves and producing capacity are added and while we believe that the deliveries will extend for some time into the future, it must be recognized that the period of most certain availability of Canadian gas tends to coincide with the period when the U.S. is less likely to require supplements. As recently as 1975 when Canadian assumptions were based on lower ates of gas discovery and higher levels of Canadian requirements, there was active consideration of terminating exports to the United States in order to protect Canada's own needs. In the present environment of reduced demand expectations both north and south of the border and of a willingness to deplete conventional reserves more rapidly than original planners might have expected, the idea that frontier gas may be needed to supplement Lower 48 and western Canadian supply may seem somewhat dated. But the fact remains that given the conservative Canadian practice of setting aside reserves for its own use first, the longer one goes out into the future, the less predictable access to Alberta and B.C. gas may be.

The Mexican pattern is somewhat different. The inflexibility of delivering associated gas, the investments in gas gathering which will be required for further developments offshore in the Gulf of Campeche, and the uncertainties surrounding how much gas Mexico wants to use for its own purposes suggests a tendency on Mexico's part to want to hold back for a time. I know there is a tendency in some quarters to discount the Mexican reluctance to increase deliveries to the U.S., particularly since Mexico was considering much larger shipments to the U.S. in 1977 than those which finally materialized. I personally believe Mexican doubts about export are genuine and would not look for a significant increase in Mexican supply for some period of time. However, if exploration develops more reserves, particularly if some of these discoveries are non-associated gas, and if the internal gas utilization policy begins to take on a more definite shape, I think we are quite likely to see a later interest in expanding deliveries to the U.S.

However, it seems to me that it will be subject almost inevitably to the same domestic set-aside constraints which Canada uses. It thus inevitably will be sensitive to the same trends in supply and demand balances within Mexico which affect the Canadian offerings.

What are the implications of all of this to North Slope gas? It is clear that the proved reserves and resources on the U.S. North Slope, perhaps some of the newer Alaskan basins, the U.S./Canadian Beaufort Sea and the Canadian Mackenzie Delta and Arctic Islands are of relatively little value without a transportation link either to U.S. markets or perhaps via tanker to Japan and Europe. The very high costs of transportation from the North Slope to U.S. markets suggests that these transportation links to the U.S. at least will not be built unless the economies of scale are there for low-cost transportation in large volumes. For such a movement to be viable, it must be backed by the assurance that there are sufficient proved reserves to support such a heavy transportation investment. If the U.S. market option is to be genuinely kept open, it is essential that reserves are not unthinkingly dedicated to other projects at a level which ultimately makes it difficult or impossible to justify access to U.S. and Canadian frontier reserves.

TABLE I

NORTH AMERICAN NATURAL GAS RESERVES AND RESOURCES

(Trillion cubic feet)

	U.S.		Canada	Mexico
Proved Reserves 12/31/82	201.7[a]		91.5[b]	75.3[c]
Percent Non-associated	71%		87%	20%
	USGS[d]	PGC[e]		
Undiscovered Resources	771	876	336[f]	180[a]
Of Which				
Conventional Areas	664	742	88	180
Frontier Areas				
Alaska	107	134	--	--
Beaufort Sea and Mackenzie Delta	--	--	66	--
Arctic Islands	--	--	80	--
Eastern Canada Offshore	--	--	86	--
Other	--	--	16	--

[a] E.I.A.

[b] Canadian Petroleum Association

[c] Pemex

[d] U.S.G.S.--Unconventional Gas Resources Excluded

[e] Potential Gas Committee--Unconventional Gas Resources Excluded

[f] Geological Survey of Canada--Average Expectation

TABLE II

AVAILABILITY OF NORTH AMERICAN PROVED GAS RESERVES TO U.S. MARKETS

(Trillion cubic feet)

	U.S.	Canada	Mexico
Proved Reserves 12/31/82	201.7[a]	91.5[b]	75.3[c]
Less Frontier Reserves	33.0	21.3	--
Subtotal Conventional Areas	168.7	70.2	75.3
Less Other Deferred Reserves	12.0	1.2	26.7[f]
Beyond Economic Reach	1.0	0.8	2.4
Committed to Markets Outside North America	0.3	2.3	--
Subtotal Available North American Supply	155.4	65.9	46.2
Less Reserved for Canadian, Mexican Markets	--	40.1[d]	41.4[e]
Canadian, Mexican Export Potential			
Contracted	--	20.7	2.0
Available Surplus	--	5.1	2.8
Maximum Potential U.S. Supply	155.4	25.8	4.8
	83%	14%	3%

Jensen Associates estimates based on:

[a] E.I.A.

[b] Canadian Petroleum Association

[c] Pemex

[d] NEB Omnibus Proceeding (25 times 1982 demand)

[e] Private communication (30 times average expected use 1982-1990)

[f] Chicontepec Reserve

Senator **Murkowski**. Thank you very much, Mr. Jensen.

I appreciate you putting your testimony in a capsulized form.

What percentage of the prebuild capacity is being carried currently through that line?

Mr. **Jensen**. Oh, it is very, very little.

Senator **Murkowski**. It is way, way under.

Mr. **Jensen**. Canada, as a whole, is operating at 43 percent of permit levels today, and the——

Senator **Murkowski**. The prebuild is what, 30 capacity?

Mr. **Jensen**. I think prebuild is—well, eastern prebuild is probably around 30 percent, and our western prebuild is probably worse.

Senator **Murkowski**. And I assume that you can make two cases; one, that maybe an error in judgment in building the capacity into that line, or, you could make another that Canadian gas is not priced at a figure that would merit more importation into the United States, which perhaps could be obtained if they would sell their gas cheaper. But they choose, for various reasons, not to. But if more gas came in in the current economic situation, it would displace domestic gas because we only have so much of a market at any given time.

Mr. **Jensen**. Right. At the moment, we have too much gas chasing too little market.

Senator **Murkowski**. Do you feel that the Canadian national energy policy has been enforced to any degree, as far as what it was originally designed to do in relationship to the state that it's in now?

Mr. **Jensen**. I'm not sure that I'd be prepared to——

Senator **Murkowski**. Well, what I'm inferring is that it would appear to me that Premier Lougheed of Alberta has been given—or he has taken pretty much a free reign in establishing what policy ultimately will be dictated with regard to the gas reserves in the Province of Alberta and the sale of those gas reserves, which at one time were in contrast to the policy expounded by the Federal Government of Canada, and it appears that for various reasons that Premier Lougheed has been pretty much successful in dictating his own provincial policies with regard to the sale of Alberta gas.

Mr. **Jensen**. The British-North America Act, and now the Repatriated Constitution in Canada, provides a much weaker link between the Provinces and the Central Government than is true in the United States. Which means that Alberta can do things that Oklahoma or Texas would never dream of being able to do in the United States.

In the course of rising oil and gas prices, the political differences between Alberta and Ottowa were intense.

If we are saying now—and we believe this, and I think the Canadians believe it—that the problem now is to back the gas prices down again, the problem of deciding how you split a declining market is a tougher one than how you split a rising market.

Senator **Murkowski**. But when you have the investments that are already established, and the prebuild and so forth, you either make gas available into this market, or you've got a problem amortizing that pipeline.

Mr. JENSEN. That's very true. Canada is not very happy moving 43 percent of what they've committed to the United States, and they are having great soul searching at the moment to try to get the volumes back up.

Senator **MURKOWSKI.** And for all practical purposes, there is every reason to think that Canada will maintain a very aggressive posture in marketing Canadian gas into the United States, because it represents, obviously, a desirable market from the standpoint of transportation proximity.

Mr. JENSEN. Right.

Senator **MURKOWSKI.** And I would assume that by that same statement, we can venture into a policy which requires, I believe, some 25-year cushion with regard to Canada's projected reserves; and, while we can't perhaps estimate what the recoverable and marketable reserves are, this estimate of a 400-year supply into the United States for the foreseeable future is based on current economic demands.

Would you comment one way or another with regard to that very broad ball park generality of the timeframes that seem to be associated with the 400-year estimate?

Mr. JENSEN. Let me define three states of the Canadian view of the market for gas in the United States.

One state is the current one in which shipments south of the border are way below plan, 43 percent of plan; and the wellhead cash flow for the Alberta producers is an acute problem in Alberta, as we have heard down here in the lower 48. The second state is the assumption that Alberta is essentially sold out; in other words, the producing capacity in Alberta is available and is moving to market.

That perception was the dominant perception in 1975, and it was expected that Alberta reserves were going to be limited in production capacity, limited for a period of time.

Now, once you say that Alberta is selling what it finds and wants to produce—which it is not now—then the question becomes, where do you turn after Alberta?

You turn to the Scotian Shelf, you turn to the frontier, you turn to the MacKenzie Delta, you turn to the Arctic Islands. And in a sense, the concept in 1975 is, we had better be careful selling those cheap Alberta reserves to the United States, because when we have to turn around and replace them it's going to cost us more money.

Now, that's not the state now. If the prebuild had not been built, the Alberta producers would be in a terrible shape, because they would be selling even less gas than the are now.

Senator **MURKOWSKI.** They'd have less debt to amortize, too.

Mr. JENSEN. The presumpt to prebuild was that it would be safe to let some of those Alberta reserves go because the Alaska pipeline and the possibility of the Dempster Lateral was there to reach the frontier.

Now, if we force them to go to the frontier on their own, the decision, once you get through Alberta and make the marginal decision for the frontier gas is is——

Senator **MURKOWSKI.** Well you're not mentioning, though, there's been substantial gas reserves found since the mid-1970's in Alberta as a result of a combination of probably exploring specifically for gas as opposed to finding gas as an offshoot of exploring for oil.

Mr. JENSEN. The surplus in gas in the United States is larger because demand has fallen, not because supply is any better than we thought it was going to be.

In Canada you have both effects operating, you have better reserve additions in production than originally was expected and——

Senator MURKOWSKI. I'm not going to ask you whether you agree with Mr. Hefner's concept of the economics of gas springing from the economics of oil.

But I would assume that one could make a comparison or an examination of the facts that the state of the marketability and policies dictated by the Canadian Government would be the major determining factor on when and if Alaska gas is marketed in the contiguous 48 States.

Mr. JENSEN. I have heard several times a question from you which suggests a hypothesis—I'm not sure you ever stated it directly. If you have not stated it directly, let me state it—and it may be wrong—and then let me answer it.

The hypothesis is that Canada will continue to add reserves to the North American pot and preempt the market that would otherwise go to Alaska. My statement is very simply, as long as Alberta and BC gas is found, and some of the frontier gas that is reasonably cheap, I think that is true, but there is a limited amount of that. And as you begin to get——

Senator MURKOWSKI. How do you determine what limited amount there is when we have no idea to what extent the area's been explored?

Mr. JENSEN. All right, that gets down, I suppose, to a major difference between Mr. Hefner and myself, and I think the one we hear in many of these hearings. Proved reserves are a demonstrable result of spending money.

Senator MURKOWSKI. For what?

Mr. JENSEN. For exploration and development.

Senator MURKOWSKI. For what, for oil or gas?

Mr. JENSEN. For gas, for oil.

Senator MURKOWSKI. In your opinion there's no difference?

Mr. JENSEN. No. I mean it is interesting that we have had several people here on the panel today who said they were gas explorationists. You can be directional. You can decide whether you're going to go look for oil or go look for gas.

Senator MURKOWSKI. Well, let me ask you this specifically. Have the reserves, the gas reserves in Alberta been found as a consequence of exploring for gas, or as an outfall of exploration for oil?

Mr. JENSEN. My assumption would be that most of the Alberta discoveries over the last decade of gas have been gas exploration.

Senator MURKOWSKI. As opposed to Alaska, which is entirely——

Mr. JENSEN. Almost oil exploration, yeah.

Senator MURKOWSKI. So we talk about the economics associated with marketing Alaska's gas—and I hate to be parochial, but that's part of my business—and the marketability of Alaska's gas is directly related then to whether or not there is either a change in Canada's policy, an increase in price which makes blending in some Alaska gas more attractive; but, in any event, something has to be done, or a change has to take place within the Canadian policy pricing or whatever because the simple economics of transportation cost and distances would dictate that Canadian gas, as long as it's available within those constraints, is going to be cheaper to bring to market than Alaska gas.

Mr. **Jensen**. Let me make a distinction again between Alberta gas as found, and frontier gas.

At the moment, the price of gas in Canada as delivered to the United States is well above market clearing levels.

We tell our Canadian clients that if there were no take-or-pay thresholds, and if everybody thought they could quietly walk away from a Canadian contract and come back with a smile and pick the gas up later on, there wouldn't be any exports from Canada to the United States today, they're over-priced.

Now, the price which is over-priced for Alberta in the current terms of the U.S. market when applied in the MacKenzie Delta and to justify a pipeline to bring that gas in would never justify it. In other words, basically what we're saying is the problem of the MacKenzie Delta and the problems of the Arctic Islands are very much the problems of Alaska, it's how do you get a high-cost transportation link between a resource and a market? It's a transportation problem.

And I don't think there's that much Alberta gas in the mixture.

Senator **Murkowski**. Well, at what point does Alberta gas become frontier gas? You can argue that back and forth because you're talking about degrees of distance.

Mr. **Jensen**. You're adding to——

Senator **Murkowski**. And technology and so forth. In Alaska, you know, there is no domestic gas, simply because there's no way to move it out. So, you know, we're left with—well, I don't want to belabor the point, but it would appear that the dictates of economics are significant from the standpoint of when and if Alaska gas is marketed in the contiguous United States. And then the question is, should we be seeking, as Canada has, other alternatives for marketing that gas? And the economics there, of course, will dictate whether that's a feasible alternative, because we're talking about marketing gas in areas of the world where there are competitive supplies at cheaper contractual prices. And probably, as Mr. Hefner inferred, there have been opportunities from time to time, windows in the market, but those windows quickly close as contracts are initiated for a significant term.

Personally, it's my observation that Southeast Asian countries with a growing concern over the quality of their lifestyle as a consequence of heavy concentrations of air pollution are going to have to look to alternative energy sources. But what potentially that's going to offer for the LNG markets I have no idea, other than I think again we have seen dramatic swings in energy here in the United States, as evidenced just by the last 10 years where we predicted substantial shortages and tremendous increase in prices that haven't occurred for a lot of reasons, conservation, switching to alternative sources and so forth.

As we both know, Mr. Jensen, Canada is exploring, and initially trying to put together long-term contracts for LNG in the Canadian Arctic. Again, it's a matter of economics.

We have the availability of Alaska gas from the Arctic and the economics of trying to compete in that same marketplace.

Again, the dictates of those who own the gas is certainly significant on when and if it's marketed. And the major holders of Alaska gas, for reasons of their own, have seen fit for the most part to support the existing proposed marketing scheme as opposed to the alternative.

And the State of Alaska, however, has perhaps a more again parochial interest in trying to establish a market for its royalty gas. And one-eights of the total volume belongs to the State. But here again, we're dealing with world economics.

I think what I made a reference to earlier in my comments though has to bear some reflection on the realities of the ANG project in its current posture. As I indicated in my general remarks, that I have had the occasion to converse with representatives of Canadian Government and Parliament, informally. They intend to hold our feet to the fire with regard to the commitments that were made with regard to ANGTS. On the other hand, they don't want to curtail the exports that are coming in from Canada, because they're looking forward to the dollars that are going into Canada as a consequence of that gas. And when confronted with "but which would you rather have, would you rather have us get on with the pipeline, or sell the gas, if you can't have both," they want to sell the gas.

And with the policy statements coming out of Canada with regard to the 25-year cushion—and we can discuss the reserves and the frontier aspects associated with Canadian gas, and make all types of estimations and throw in, you know, the optimistic assessment of Mr. Hefner with regard to the reserves, and the more pessimistic that you have, but we're still looking at potentially a long, long time before there's likely to be a change in that scenario, all things being equal.

That's no profound observation to make, that all things aren't equal, but it's fair to say that my particular State is interested in pursuing to see whether there is potentially an alternative for marketing Alaska gas.

And it's no secret—and I think it was expressed by Mr. Wolf—I'm doing somewhat of a summary here—that the reason the independents aren't in Alaska for gas is there's no way they can market it, and that gas has been found in Alaska as a consequence of the search of oil.

And, you know, every time I utter a figure on the gas reserves, I'm underestimating. You know, the last figure we used was 27 Tcf. Now, it's more than that.

The Canadian reserves by the Canadian Government are 80 Tcf. Now, we're using a figure of 90.

I think if we were to flip back a few pages we would find that there appears to be, from the experts' testimony, more and more reserves being found.

In any event, I think that what we have accomplished here today is to get a fair evaluation that the industry left alone, without Government interference, could probably do pretty well establishing itself, perhaps more unrelated to how we generalize oil and gas. And I think your testimony, Mr. Hefner, particularly was helpful to me, because I think it's probably time that gas stood on its own merits; wasn't associated necessarily with oil. We generalize too much.

I can't help but think that with the significant charts that you showed that, you know, there's a tremendous opportunity to market more gas as an alternative to some of the problems.

I listen to my colleagues in the Northeast corridor complain about potential fallout of acid rain. And whether you argue where it's coming from, whether it's coming from the Ohio Valley or what not, gas and nuclear are the only viable alternatives if you're going to really do something about the problem, because you face technological costs associated with conversion of coal and crude oil that you don't have.

So rather than bury our head in the sand—it's easy to say we ought to do something about it, but I think your efforts to, if you will, split the industry and let each stand on its own can have some far-reaching impacts on a number of my colleagues, who have a tendancy to generalize the industry as a gas and oil industry as opposed to standing separate and apart.

So I thank you for that.

I think Mr. Wheeler had a comment that he wished to make, and I would ask that you go ahead and make it, Mr. Wheeler.

Mr. WHEELER. I would like to say that we, in Exxon, and I think other major companies are actively exploring for gas.

I'm in charge of our exploration, I know we're looking for gas. We may not have been—industry may not have been in the late 1950's and 1960's when gas was priced at 10 or 20 cents an Mcf, and that may have been shortsighted, but that is not the case today.

I would just like to say a brief word in defense of the estimate that I presented earlier. I don't want to debate the estimate with Mr. Hefner. We, neither of us, can prove who is right, and we could go on forever.

I just want to say that our estimate is not taken with an ulterior purpose. It is a geological estimate, it is not a projection of past finding rates or anything of the sort. It's a consciencious effort to look at all the potential of all the areas that he talked about. And I agree with him that there is tremendous additional potential in deeper horizons in the basins that he mentioned, and we think we have allowed for that.

Senator MURKOWSKI. Is Exxon exploring for gas in the North Slope and Prudhoe Bay?

Mr. WHEELER. Not actively exploring for gas in the North Slope, that is correct. Although we have taken leases which we think are gas prone, but we're not drilling on prospects which we think will be gas.

Senator MURKOWSKI. Is Imperial actively exploring for gas in the frontier Arctic of Canada?

Mr. WHEELER. Looking for oil in the frontier Arctic of Canada.

Senator MURKOWSKI. So it's fair to say that you are perhaps exploring for gas in areas where you have an integrated transportation system already in effect.

Mr. WHEELER. Very much like Mr. Wolf said, where it's economical to go ahead, that's right.

Senator **Murkowski**. But the economics of one routing and marketing for gas don't always preclude consideration of another potential market for gas, but that appears to be the posture your corporation is taking with regard to marketing its holdings within Alaska.

Mr. **Wheeler**. Well, we question any availability—I mean the Japanese market, as for example, if that's—I'm not saying we wouldn't favor a project to Japan if there were truly economics to go with it. I question that they're there.

But the Japanese market doesn't need a lot of gas today. There is a lot of competition for that Japanese market. I think the price that you're going to see in the net-back that Alaska will see from which to derive royalties and other income is going to be limited.

Senator **Murkowski**. Well, it just depends on what you're comparing it with, and there's nothing there now.

Mr. **Wheeler**. You're right.

Senator **Murkowski**. I thank you gentlemen for being with us so late.

The record will be open for a period of 2 weeks. I think it's been a worthwhile effort to get some fresh ideas and rehash some new ones and be a little parochial about a project that is of interest to our State, because we're realistic enough to recognize that anything produced out of Alaska is a result of a significant find or it's not produced. That's the first rule of thumb. And that with the exception of oil, nothing we produce is marketed in the continental United States. And as you all know, oil is by congressional action dictated to be marketed within the United States, with no provision for allowance of any marketing outside the United States. So we feel we have some rather unique congressional treatment in the marketing of some of our resources.

But in any event, we have examined the gas supply and reserve and potentials of North America relatively thoroughly. We haven't had any experts from Mexico or Canada, but that's all right, we've got adequate U. S. experts to address that subject.

I think it has been extremely interesting to reflect, if you will, on the continued differences of policy between the independents and the majors, and it's evident why the two exist within their sphere of activity and influence, and yet enjoy the competitive spirit that has been evidenced within the industry for some time.

But it would be my hope that I can share as a consequence of this record, perhaps, the view that it's time to look at the oil industry as separate from the gas industry and recognize some of those differences.

So with that profound observation, I'll thank you again, and wish you a good day.

The hearing is adjourned.

[Whereupon, at 6:15 p.m., the hearing adjourned.]

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